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Interim Report, Work Group 3B

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This is an Interim Report prepared by a US/Canada Work Group in accordance with the Memorandum of Intent on Transboundary Air Pollution concluded between Canada and the United States on August 5, 1980.

This is one of a set of four reports which represent an initial effort to draw together currently available information on transboundary air pollution, with particular emphasis on acid deposition, and to develop a consensus on the nature of the problem and the measures available to deal with it. While these roports contain some information and analyses that should be considered preliminary in nature, they accurately reflect the current state of knowledge on the issues considered. Any portion of these reports is subject to modification and refinement as peer review, further advances in scientific understanding, or the results of ongoing assessment studies become available.

Other Tansboundary air pollution issues will also be included.

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ON
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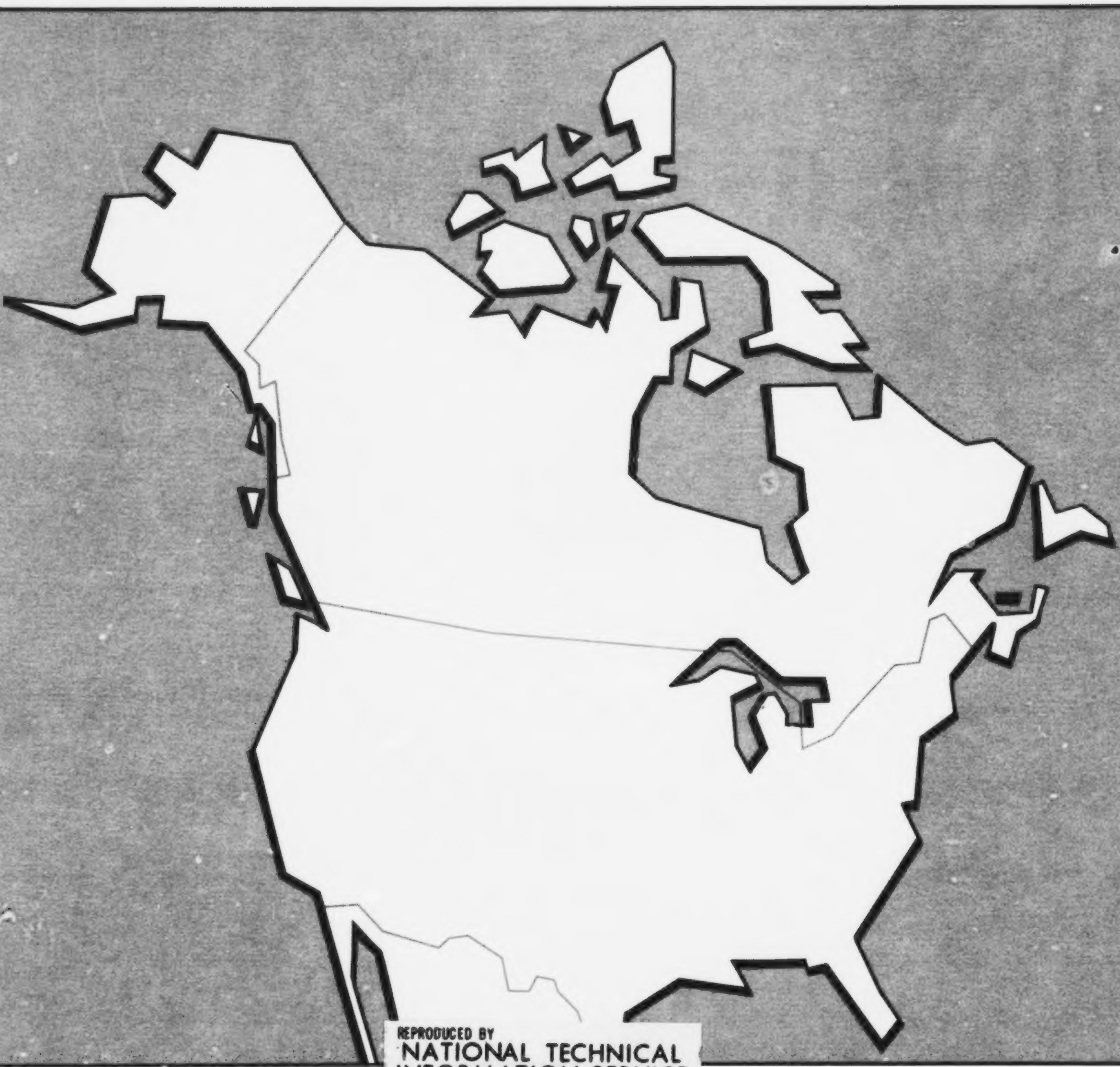

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EMISSIONS, COSTS AND
ENGINEERING ASSESSMENT
INTERIM REPORT
FEBRUARY 1981

WORK GROUP 3B
ENGINEERING, COSTS AND EMISSIONS
INTERIM REPORT
JANUARY 15, 1981

January 15, 1981

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Dear Messrs. Hawkins and Robinson:

We are pleased to submit the interim report from Work Group 3B for your submittal to the Coordinating Committee. I understand that this report will be reviewed by the Coordinating Committee at its meeting on January 29, 1981.

The interim report is an initial effort by Work Group 3B to fulfill its terms of reference. The more extensive report to follow in May 1981 is intended to provide information in support of the negotiations as called for in the Memorandum of Intent.

With the completion of this report, Work Group 3B is in a good position to begin activities in Phase II.

Sincerely yours,

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PREFACE

The Emissions, Costs, and Engineering Assessment Subgroup (Work Group 3B) was established under the MEMORANDUM OF INTENT in order to provide support to the development of the control element of the bilateral agreement on transboundary air pollution. Work Group 3B is also charged with preparing proposed work under the Applied Research and Development element of the agreement.

The purpose of this Phase I report is to respond to the Terms of Reference identified in the MEMORANDUM OF INTENT and to the tasks set forth in the group's approved work plan. During Phase I, Work Group 3B has devoted its efforts to:

a. Preparing a work plan for Phase I and Phase II
b. Identifying control technologies and associated costs for source categories of major concern
c. Reviewing historical emission trends
d. Determining current emission rates from the source regions
e. Projecting future emission rates under varying control and economic conditions
f. Preparing the Phase I report

During Phase II, the group will:

a. Prepare a work plan for Phase III
b. Conduct a series of iterative analyses in order to evaluate different pollution control scenarios
c. Prepare the Phase II report

Due to time and resource constraints, it has not been possible to treat all emissions and source categories equally. Although some source categories have been covered only lightly, we have attempted to treat intensively those source categories thought to be major contributors to transboundary air pollution problems. Some work remains in order to reconcile our results with those of the other work groups, especially Work Group 2. During Phase I, the emphasis has been placed on compiling as much information as possible on the major precursors of acid precipitation (i.e., sulphur and nitrogen oxides) and the primary sources of these emissions. A major effort will be undertaken during Phase II to upgrade the information presented in this document and to analyze various emission control strategies for the sources of acid deposition.

The first chapter of this report summarizes the major findings and conclusions in terms of the major analytical elements: emissions, technology for control, and costs. The remainder of the report is structured to closely follow the Terms of Reference for Work Group 3B. Chapter B presents data and information on emission control technologies and associated costs for all major source categories. Chapter C analyzes the historical emission trends for the United States and Canada while Chapter D presents data on current emissions for the two countries. Chapter E projects U.S. and Canadian emissions for various source categories through the year 2000. The final chapter of this report lays out the future course of action for Work Group 3B and suggests some future R&D needs.

This document is only the Phase I report and is expected to undergo substantial revision in succeeding phases. In its current form, the report is a good "strawman" for the Work Group's future efforts, and ultimately in its final form (at the conclusion of Phase II) will provide the technical basis for negotiations between the United States and Canada for an agreement covering the major aspects of transboundary air pollution.

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A. SUMMARY OF FINDINGS AND CONCLUSIONS

A.1 INTRODUCTION

This is an interim report by Work Group 3B (Emissions, Costs and Engineering Assessment) as part of the commitment in fulfillment of the requirements of the MEMORANDUM OF INTENT signed by the United States and Canada on August 5, 1980. The Terms of Reference and the membership for Work Group 3B can be found in Appendix 1 of this report.

This report reviews, in detail, the technologies (process and control), costs of application of controls for the reduction of SO_2 and NO_x emissions (for both new and retrofit installations; costs for retrofit installations are generally greater than for new installations), and emissions (historical, present and projected) for the thermal power industry sector (eastern U.S. and Canada), non-ferrous smelters (eastern Canada) and mobile sources (U.S. and Canada). These sectors, together with industrial, residential and commercial fuel combustion, account for the majority of the SO_x and NO_x emissions in the eastern part of North America, and hence are judged to be the most important sources in the acid precipitation problem. A more brief review is carried out for petroleum refining, solid waste incineration and pulp and paper. These sectors are considered to be of secondary importance to the acid precipitation problem since their emissions of SO_x and NO_x are considerably smaller in magnitude than those of the three primary sectors. Note that all emissions in Chapter A are in short tons, while emissions in subsequent chapters are partly in short tons and partly in tonnes (metric).

Included in this report are recommendations for future R&D activities and conclusions and recommendations concerning the control of SO_x and NO_x emissions.

A.2 THERMAL POWER - CONTROL TECHNOLOGY SUMMARY

SO_x Reduction

Control of SO_2 emissions has become a complex problem with several options available and many factors involved in making the choice between them. One of the main problems is that some of the factors are intangible in nature and are therefore difficult to quantify.

Sulphur oxide emissions can be reduced by several methods

1) use of naturally occurring low-sulphur fuel
2) removal of the sulphur before combustion
3) reaction with an absorbent during combustion
4) removal of the sulphur after combustion

In rating the alternatives for SO_2 control, the major consideration is the degree of control required. Some processes are capable of a very high removal efficiency but are expensive; others cost much less but are limited to a relatively low level of removal efficiency.

The following recommendations are made for process choice at different required levels of emission reduction. It should be noted that these are only approximate and that site-specific conditions could well change the ranking. The rankings are judgmental in nature, based on a subjective evaluation of factors such as cost, commercial viability, absorption efficiency, and process reliability. A more quantitative approach to ranking does not seem feasible in view of all the uncertainties involved.

Removal efficiency level, %	Process listing
Higher than 90%	1. Double alkali
	2. Limestone scrubbing with promoters
	3. Coal gasification (combined cycle)[a]
	4. Regenerable scrubbing processes
90%	1. Limestone scrubbing with promoters
	2. Limestone scrubbing
	3. Double alkali

---

[a] When and if developed.

50-90% (high-sulphur coal)	1.	Limestone scrubbing (with physical coal cleaning where upper limit on SO_2 emission applies)
	2.	Fluidized-bed combustion[a]
	3.	Chemical coal cleaning
	4.	Low-sulphur fuel substitution (not a sulphur removal process)
	5.	Limestone injected through modified burner[b]
50-90% (low-sulphur coal)	1.	Spray drier process
	2.	Limestone scrubbing
Below 50%	1.	Physical coal cleaning
	2.	Blending with low-sulphur coal

---

[a] When and if developed.

[b] Under development.

Table A.2.1 summarizes the cost data available for sulfur oxide controls on thermal power plants. Physical coal cleaning costs approximately $15 per ton of coal for high-sulfur coals (i.e., approximately $0.22 per pound of sulfur removal). (For low-sulfur coals the price is considerably higher i.e., around $1.88 per pound of sulfur removal).

The cost for flue gas desulphurization (FGD) ranges between $120 - $200 per kilowatt of installed capacity. Using lime instead of limestone raises the costs. FGD recovery processes, such as the dual alkali and Wellman-Lord processes, tend to be more expensive than wet scrubbling. Dry scrubbers cost $120 - $140 per kilowatt of installed capacity but the technology is still under development and the cost estimates are rising. Generally, there is a wide range in the costs of FGD systems due to site-specific variables.

NO_x Reduction

Several approaches can be used for NO_x control. Low-nitrogen fuel is one of these but is not as effective as low-sulphur fuel is for SO_2 because part of the NO_x comes from the combustion air rather than the fuel. Combustion modification, the most cost-effective method, is used to some degree. If flue gas treatment is required, injection of ammonia to reduce NO_x to nitrogen is favoured. Use of a catalyst promotes the reaction

Table A.2.1

CONTROL TECHNOLOGIES FOR SO_2 REDUCTION

SYSTEM	PERFORMANCE	COST	APPLICABILITY	UNCERTAINTY	WASTE DISPOSAL	PROBLEMS
Wet F.G.D. Limestone Lime	Acceptable Availability (90% or >)	Limestone: $120-$200/kW Lime: ~$200/kW	All fuels	Cost is a function of size, sulphur content, location, redundancy of equipment, whether ash removal included.	Preferably oxidized to gypsum, otherwise settling problems in ponds and landfill, unless chemically fixed.	Waste disposal because of volumes. Utilities sceptical of costs and reliability.
Dual Alkali	Acceptable Availability	Actual $80-$242/kW	All fuels	Limited experience.	As above.	As above.
Wellman Lord	Limited experience so far.	Actual $259/kW	All fuels	Uncertain market for by-products.	Potential water pollution problem.	High Cost.
Dry Scrubber	Limited experience so far.	$120-$140/kW including e.s.p., but rising	Low sulphur fuels	Performance data sparse.	Lime systems have minimal problems, whereas soda-based units have potential water pollution problems.	Waste disposal involves large volumes. Operational difficulties with variations in coal characteristics.
Low-Sulphur Fuel		Coal Cost dependent very much on transport distance & charges.	Coal	Incremental costs, availability of supplies.	No problem.	Boiler derating, effects on precipitator, transportation, logistics.
		Oil Adds $5 per barrel	Oil	As above.		
Physical Coal Cleaning	Effective up to 25% sulphur removal.	Can add up to $15 per ton.	Used for high pyritic sulphur coals.	Coal variability and expansion of existing facilities	Water pollution and solid waste disposal.	Energy losses, maintaining quality control.

and is preferred over non-catalytic operation. Various wet scrubbing methods have been developed but none seems very promising.

The situation for NO_x is the same as for other pollutants. The selection of abatement method depends on the degree of control required. A rough ranking is as follows:

Removal efficiency level, %	Process listing
90% or higher	1. Catalytic reduction[a] with more than normal amount of catalyst, preceded by combustion modifications
50-80%	1. As above, with normal amount of catalyst
	2. Combustion modifications (all types) followed by non-catalytic reduction (ammonia injection without catalyst)
	3. Combustion modifications alone (for low part of range so as to minimize boiler problems)
	4. Low-NO_x burners
Below 50%	1. Staged combustion[b]
	2. Low-NO_x burners[b]
	3. Gas recirculation (except for coal[b])

---

[a] Technology has not been proven with respect to coal-fired boilers.

[b] Used in combination with others if necessary to achieve the required reduction level.

The capital costs associated with the use of combustion modification techniques for the control of NO_x emissions from thermal power plants are estimated at:

Techniques	Capital Cost	NO_x Emission Limit
Low Excess Air	\$0	0.9 lb per 10^6 Btu
Staged Combustion (over-fired air)	\$2-3/kW	0.7 lb per 10^6 Btu
Low-NO_x Burners	\$2-\$10/kW	0.4-0.5 lb per 10^6 Btu

The capital cost estimates for NO_x control vary considerably due to site - specific variables (e.g., boiler type). The uncertainity in the cost data ranges from -10 percent to +30 percent. Furthermore, the cost of flue gas treatment (FGT) processes for NO_x control have not yet been determined.

A.3 NON-FERROUS SMELTING SUMMARY

The process technology in use varies from smelter to smelter. A majority of the smelters use the roaster - reverberatory furnace - converter process which is not amenable to a high degree of SO_2 control, at reasonable cost, owing to the weak gas streams produced. Some copper-nickel smelters utilize more modern process technology, and in some cases SO_2 emissions are controlled. (Level of control varies from smelter to smelter.)

The most applicable control technology in use is the production of sulphuric acid in a contact acid plant. Two constraints limit the use of this control technology:

- weak SO_2 streams (under 4% SO_2) are not suitable for contact acid plants and a number of smelters do not have strong gas streams;
- markets for sulphuric acid are limited, and it is possible that not all the acid produced could be marketed.

For any major SO_2 control program to succeed it would be necessary to:

- improve or replace existing process technology (with weak SO_2 streams) with new process technology which produces higher-strength SO_2 streams (suitable process technology is available in the majority of the cases); and

b) find markets for the sulphuric acid.

Two other problems areas are identified:

- in many smelters, some weak gas streams will remain, even with new process technology, and SO_2 emission control technology for weak gas streams in this sector is in the early development stages; and
- the choice of smelter processes to handle dirty concentrates is limited, which in turn may reduce the level of SO_2 control achievable at smelters handling dirty concentrates.

A preliminary cost estimate has been developed for eastern Canadian copper-nickel smelters. The estimated cost of reducing eastern Canadian smelter SO_2 emissions (at capacity operations) from 2.97 million tons per year to 1.30 million tons per year is $1.1 billion capital and $120-$150 million annualized costs (includes both capital and incremental operating costs).

A.4 MOBILE SOURCES SUMMARY

The mobile sources sector is a major source of NO_x emissions. SO_x emissions from this sector are small and have not been considered in the interim report. Control technology is available for the control of NO_x emissions from mobile sources. The use of the newer NO_x control technologies is being expanded and NO_x regulatory emission limits are gradually being reduced for new vehicles.

NO_x emissions from "in-use" vehicles are becoming a major part of the mobile sources NO_x problem and new programs are addressing this problem by legislating improved maintenance requirements for such vehicles. These programs, coupled with more stringent new-vehicle NO_x emission limits, should reduce total NO_x emissions from mobile sources, despite the continuing increase in the total number of vehicles.

The technology for meeting the current automobile emission standards employs the catalyst technology, coupled with a series of electronic and vacuum sensing devices which detect and control selected engine operating parameters. A so-called three-way catalyst (incorporating NO_x reduction as well) is being used on many of the 1980 production cars. The system costs approximately $300 per car. Including fuel and maintenance savings, the cost of the U.S. Federal Motor Vehicle Control Program (FMVCP) for cars, trucks, heavy-duty vehicles, motorcycles, and aircraft is estimated to be $6.6 billion by 1987. The cost of the inspection and maintenance component of this program is estimated at $400 million annually.

A.5 INDUSTRIAL, COMMERCIAL, AND RESIDENTIAL FUEL COMBUSTION

Industrial, commercial and residential fuel combustion accounts for approximately 25 percent of combined U.S.-Canada SO_2 emissions and approximately 25 percent of their combined NO_x emissions. The fuel use sector is characterized by a wide diversity in boiler sizes (i.e., from 10^5 Btu/hr to greater than 250×10^6 Btu/hr), combustion systems, and fuel characteristics. In addition, the technical expertise of the owner/operator varies from the homeowner to the skilled technician. Industrial boilers are the major concern in this sector.

Flue gas desulfurization can lower potential sulfur oxide emissions by up to 90 percent. Fluid bed combustion can achieve a 70-85 percent SO_2 reduction at costs which are competitive with flue gas desulfurization. The dual-alkali wet flue gas desulfurization process is the dominant sulfur oxide control technology for industrial boilers. Sodium once-through systems are used in industries which produce a sodium-containing waste stream such as pulp and paper and textile mills (from de-ionizer recharging). There are two commercial installations of the lime spray dryer SO_2 control process.

As in utility boilers, combustion modification is the principal method of controlling NO_x emissions. In California, several thermal-NO_x (non-catalytic NO_x control) installations have been purchased; however, none is in commercial operation at this time. The NO_x emission limits that are achievable using combustion modification are dependent upon the fuel type (oil, coal, gas) and firing method (for coal, pulverized coal, chain-grate stoker, vibrating-grate stoker, and spreader stoker).

The cost of SO_2 control technology varies as a function of boiler size, load factor, and fuel sulfur content. Thus the uncertainty in capital and annual costs can be large. The capital costs and operating costs shown in Figures A.5.1 and A.5.2 can be in error by as much as ±40 percent. The cost of retrofitting industrial boilers is highly uncertain since space limitations and other restrictions can cause significant variations.

Control technology for commercial and residential boilers has not progressed as rapidly as for the larger boilers, primarily because of the considerably smaller emission reduction potential for this sector. However, results of research indicate that some emission reduction is economically possible for commercial and residential boilers. Precise cost figures for these boilers are not available, but preliminary indications are that any increase in cost will be greatly offset by the fuel savings and increased thermal efficiency.

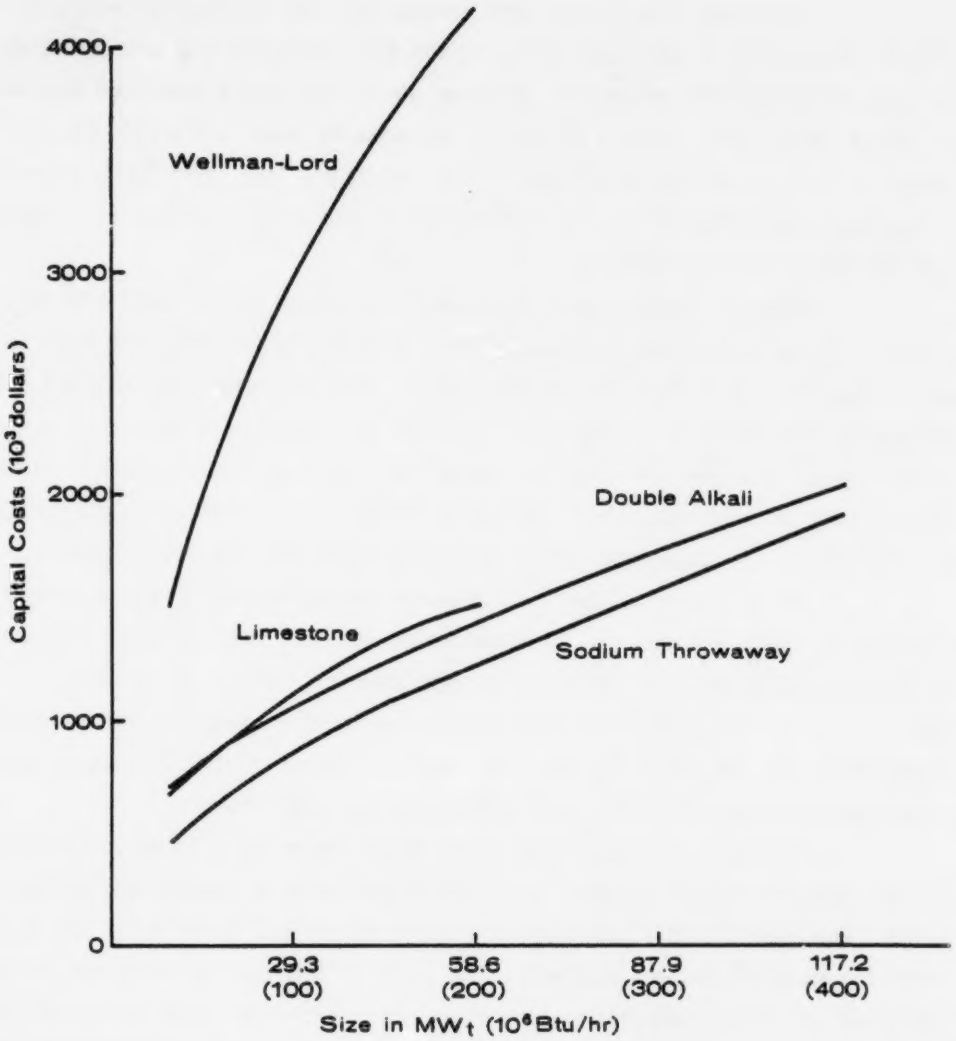

FIGURE A.5.1 FGD CAPITAL COSTS VERSUS UNIT SIZE
(3.5% S coal, 90% removal)

Source: Technical Assessment Report for Industrial Boiler Applications:
Flue Gas Desulfurization
Industrial Environmental Laboratory; USA E.P.A.
November 1979

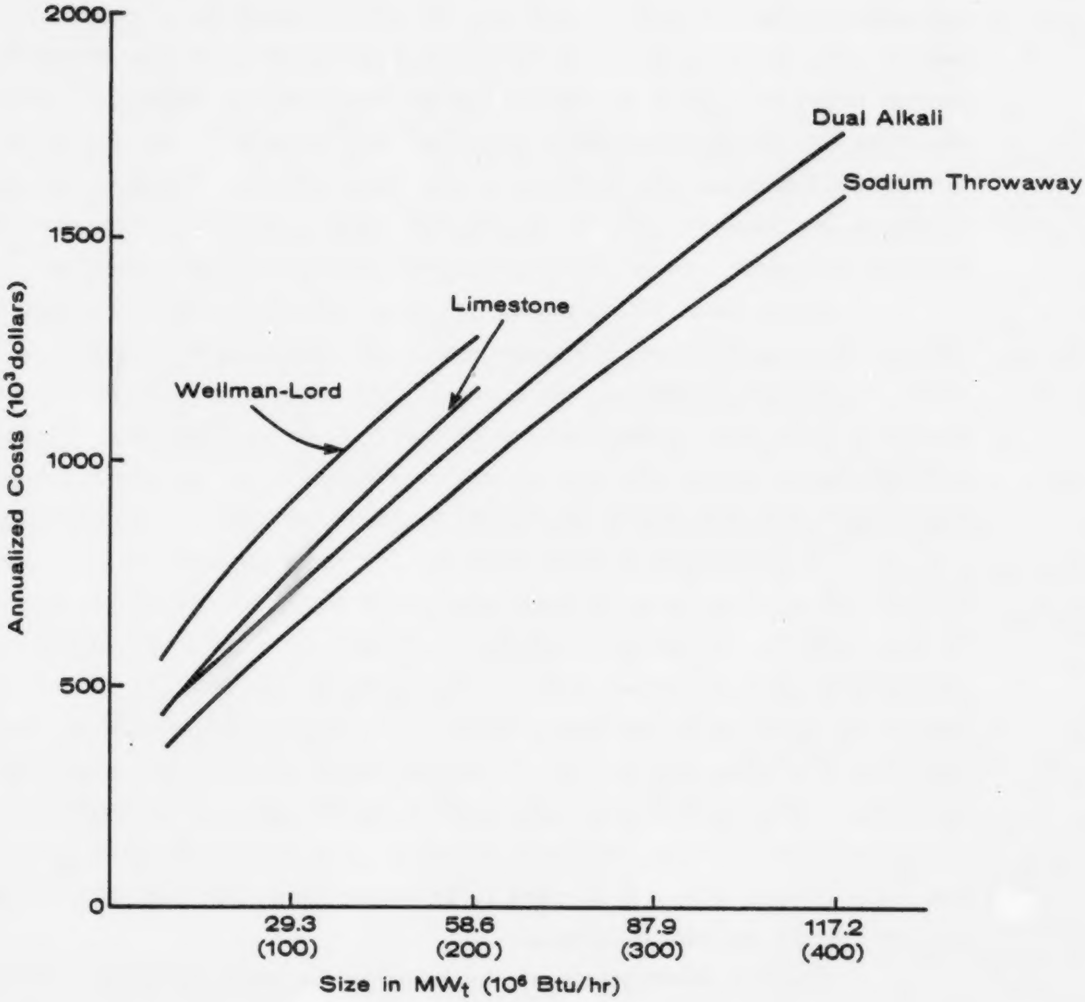

FIGURE A.S.2. FGD ANNUALIZED COSTS VERSUS UNIT SIZE (3.5% S coal, 90% removal)

Source: Technical Assessment Report for Industrial Boiler Applications:
Flue Gas Desulfurization
Industrial Environmental Laboratory; USA E.P.A.
November 1979

A.6 EMISSIONS SUMMARY

Historical, present, and projected emissions of the main acid precipitation precursor pollutants in both Canada and the United States are assessed. The data have been accumulated in a variety of formats and are presented in this interim report in the form of tables and figures, on the basis of the sectors of the economy of most concern at this time, at the state, regional, provincial and national levels, and on a grid array. Confidence limits are put on some of the data, seasonal variations for some of the emissions are assessed, and an insight into natural sources of emissions is provided. Projected emissions are analyzed according to a variety of control scenarios.

Emissions of SO_2 in the eastern U.S. rose from close to 12 million tons in 1950 to about 25 million tons in 1965 before essentially stabilizing at that level up to the year 1978. In eastern Canada SO_2 emissions in 1979 were about 4.5 million tons, the same level as in 1955, after having peaked in 1965 at close to 6 million tons. The southeast and midwest states shared the bulk of the increase in U.S. emissions. In Canada the fluctuation was largely due to significant changes in the copper-nickel smelting industry.

NO_x emissions in the eastern U.S. increased significantly in all areas over the 1950-78 period. The steady increase ranged from about a factor of two in the northeast to over three in the south. Emissions which were at a level of 7 million tons in 1950 reached more than 19 million tons in 1978. In eastern Canada NO_x emissions have also been rising significantly but from a level of less than 0.5 million tons in 1955 to a little less than 1.5 million tons in 1977. In eastern North America as a whole the important increases in NO_x emissions are attributed to power plant and transportation activities. During the 1976-80 period, yearly SO_2 emissions in eastern North America (i.e., both U.S. and Canada) have amounted to close to 29 million tons. The ratio of U.S. to Canadian SO_2 emissions in the east is 5.5 to 1.

Thermal power plants are the primary source and contribute about 60% of the combined U.S.-Canada nationwide emissions. The second most important category of emission sources, at about 25% of the combined nationwide emissions, is that which includes industrial, commercial, and residential fuel combustion. Then at about 10% are the emissions of SO_2 from non-ferrous smelters. The primary contributor to present domestic SO_2 emissions differs in the U.S. and Canada. In the U.S. about two-thirds of total domestic emissions come from power plants, while in Canada about 40% come from non-ferrous smelters. About 20 million tons of SO_2 comes from American power plants, about 2 million tons of SO_2 comes from Canadian non-ferrous smelters. About 15% of the SO_2 generated in Canada comes from thermal power plants.

In the next two decades, U.S. SO_2 emissions from power plants are projected to remain roughly constant (in fact, recent evidence suggests they may even decline). In Canada, SO_x emissions from thermal power plants are expected to increase from 0.8 million tons (1980) to 1.4 millions tons (2000) unless controls are instituted for thermal power plants. With controls, Canadian SO_2 emissions from thermal power plants could decrease.

In eastern North America present NO_x emissions amount yearly to almost 21 million tons. The ratio of U.S. to Canadian emissions in the east is roughly 15 to 1, and close to half of the combined emissions come from the transportation sector. One quarter of combined U.S.-Canada NO_x emissions are contributed by power plants and another quarter by other combustion processes (industrial, commercial, residential fuel combustion).

With respect to NO_x discharges from power generating stations, an increase of about 50% is projected by the year 2000 from U.S. units. In Canada, uncontrolled NO_x tonnage is expected to rise from 330 kilotons per year to 700 kilotons by the end of 2000. If lax controls were applied, to the same new and existing stations as considered above for SO_2 reductions, emissions would decline by about 80 kilotons or 15%. If strict controls were added, the reduction would be to 150 kilotons or 77%.

Transportation sector emissions in the U.S. in the next 15-20 years are not expected to vary significantly from their present levels because of larger numbers of lower-emitting vehicles, unless projected automobile regulations are relaxed. In Canada, in the absence of further control action at either the design or in-use levels, NO_x emissions in 1990 are projected to be 30 to 50% greater than present levels. If, however, more stringent new-vehicle emission standards were adopted with the 1985 models, then NO_x emissions in 1990 would be about 20% less than 1980 levels. In both countries the tampering rate might be reduced by an inspection program on in-use vehicles.

Projected SO_2 emissions from Canadian copper-nickel smelting complexes to the year 2000 indicate at worst the same level as in 1980, i.e., less than 2.0 million tons per year, and at best a level of 0.8 million tons. The level attained will depend on the implementation of additional environmental control and technological improvements. In the U.S. the SO_2 emissions come from copper smelters located in western and south-western states and are therefore unlikely to play a significant role in the eastern North America acid precipitation issue.

SO_2 emissions from industrial, commercial and residential fuel combustion are projected to increase about 50 percent in the U.S. over the next two decades (i.e., from 7.3 million tons in 1980 to 10.9 millions tons in 2000). NO_x emissions from these sources will also increase significantly (i.e., from 7.1 million tons in 1980 to 9.1 millions tons by the year 2000). In Canada, SO_2 and NO_x emissions from industrial, commercial and residential fuel combustion will also increase but not significantly. For SO_2 emissions, the increase is from 1.1 million tons to 1.2 million tons (10 percent); for NO_x, the increase is from 0.6 million tons to 0.7 million tons (20 percent).

Present SO_x and NO_x emissions data for the U.S. and Canada are presented in Table A.6.1. Projected SO_x and NO_x emissions for the U.S. and Canada are presented in Tables A.6.2 to A.6.4. These projections are based on "status quo" considerations and do not include any major emission reduction resulting from significant control measures of the acid precipitation program.

TABLE A.6.1 CURRENT NATIONWIDE EMISSIONS OF SO_x AND NO_x IN THE U.S. AND CANADA (10^6 tons)

	U.S.A. (1980 Estimated)		Canada 1979*		Total	
	NO_x	SO_x	NO_x	SO_x	NO_x	SO_x
Utilities	6.2	19.5	0.3	0.8	6.5	20.3
Industrial Boilers/ Process Heaters/ Residential/Commercial	7.1	7.3	0.6	1.1	7.7	8.4
Non-ferrous Smelters	0.0	2.0	0.0	2.2	0.0	4.2
Transportation	9.0	.9	1.1	0.1	10.1	1.0
Iron Ore Processing	-	-	-	0.2	-	0.2
Other	-	-	0.2	0.9	0.2	0.9
TOTAL	22.3	29.7	2.2	5.3	24.5	35.0

* Inco, Sudbury at 1980 emission rate.

TABLE A.6.2 PROJECTED EMISSIONS OF SO_x AND NO_x IN CANADA (10^6 tons)

	Year 1980	1985	1990	1995	2000
NO_x TRENDS					
Utility Boiler	0.3	0.4	0.6	0.6	0.7
Industrial, Residential and Commercial Fuel Combustion	0.6	0.6	0.7	0.7	0.7
Non-ferrous Smelters (Cu/Ni)	-	-	-	-	-
Transportation	1.1	1.3	1.5	1.6	1.8
Other	0.2	0.2	0.2	0.2	0.2
TOTAL	2.5	2.5	3.0	3.1	3.4
SO_x TRENDS					
Utility Boiler	0.8	1.1	1.2	1.3	1.4
Industrial, Residential and Commercial Fuel Combustion	1.1	1.1	1.2	1.2	1.2
Non-ferrous Smelters (Cu/Ni)	2.2	2.0	2.0	2.0	2.0
Transportation	0.1	0.1	0.1	0.1	0.1
Iron Ore Processing	0.2	0.2	0.2	0.2	0.2
Other	0.9	0.9	0.9	0.9	0.9
TOTAL	5.3	5.4	5.6	5.7	5.8

Source: Data Analysis Division, Air Pollution Control Directorate, Environment Canada

Note: Based on a "status quo" scenario.

TABLE A.6.3 SO_x PROJECTED EMISSIONS USING COMBINED MODELS (UNITED STATES) (10^6 tons)

	1980	1985	1990	1995	2000
Utility Boiler	19.5	17.9	18.6	19.0	18.5
Industrial Boiler/Process Heat	5.9	5.7	6.8	8.6	10.3
Non-ferrous Smelters	2.0	0.77	0.60	0.56	0.52
Residential Commercial	1.4	1.4	1.2	0.9	0.6
Transportation	0.9	0.9	0.9	0.9	0.9
TOTAL	29.7	26.7	28.1	30.0	30.8

Source: These emissions estimates based on 1980 trends but projected with % change of models (utility - TRI; industrial ICF; RES/COM - SEAS; Transportation Ann Arbor), NF Smelters from an actual unit-by-unit survey.

TABLE A.6.4 NO_x PROJECTED EMISSIONS USING COMBINED MODELS (UNITED STATES) (10^6 tons)

	1980	1985	1990	1995	2000
Utility Boiler	6.2	6.8	7.6	8.4	9.2
Industrial Boiler/Process Heat	6.2	6.5	6.9	7.6	8.4
Non-ferrous Smelters	0.0	0.0	0.0	0.0	0.0
Residential Commercial	0.9	0.9	0.8	0.8	0.7
Transportation	9.0	8.3	8.6	9.4	10.2
TOTAL	22.3	22.5	23.9	26.2	28.5

Source: These emissions estimates based on 1980 trends but projected with % change of models (utility - TRI; industrial ICF; RES/COM - SEAS; Transportation Ann Arbor), NF Smelters from an actual unit-by-unit survey.

B. SOURCE SECTORS OF CONCERN

This chapter describes the industry sectors that are major sources of SO_x and NO_x, and the control technologies that are either currently available or will be in the near future. The emission sources discussed are thermal power plants (fossil fuels), non-ferrous smelters, mobile sources (transportation), pulp and paper, petroleum refining, industrial, residential and commercial fuel combustion and incinerators. Other sectors, such as iron ore processing plants, will be addressed in a subsequent report.

Each sector is described in terms of the production processes and capacities and SO_x and NO_x emissions. This is followed by discussions of the control technologies in use, available or emerging for each industry sector. The control technologies are analyzed in terms of performance, cost, applicability, technical uncertainty and associated problems. Alternative production processes are also discussed where applicable.

B.1 THERMAL POWER

B.1.1 DESCRIPTION

The Canadian Sector

Canada's electrical generating capacity is expected to increase substantially by 1990, exceeding 1977 capacity by over 60 percent (1). This expansion will be noticeable in all three major types of generation: hydroelectric, nuclear, and conventional thermal. Hydroelectric power will maintain its leading role in the utility sector, nuclear power will grow by a factor of three, while thermal generation will increase to a somewhat lesser degree, by about 50%.

Conventional steam-electric capacity, at 19 184 megawatts (MW) in 1977, is expected to increase to approximately 28 900 MW by the end of 1989 (1). All announced steam-unit additions by 1990 will be coal-fired. This added coal-burning capacity will cause annual coal consumption to increase by 127 percent, from about 21 000 kilotonnes in 1977 to approximately 48 000 kilotonnes in 1989. The majority of the steam-unit additions fall in the provinces of Alberta and British Columbia.

Table B.1.1 shows each province's percentage distribution of installed capacity by generation type for both 1977 and 1989. The type categories are standard: coal, oil, gas, nuclear, hydro, gas turbine, and internal combustion.

The breakdowns for 1977 are from the reports of installed capacity; those for 1989 are from the schedule of expansion plans. The 1989 distributions do not include the effects of any capacity penalties due to pollution control devices and therefore represent the distributions that would occur in the case involving no active pollution control. The changes in the distributions due to the imposition of pollution control penalties are not great.

In Table B.1.2 the generation mix by province is presented for the two years 1977 and 1989. Note that Nova Scotia, Saskatchewan, Alberta, and British Columbia substantially increase the share of their generation from coal units. In

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(1) Statistics Canada, Electric Power Statistics, vol. 1, Annual Electric Power Survey of Capability and Load - 1979-1983 Forecast, 57-204 Annual (Ottawa, Ont.: Manufacturing and Primary Industries Division, Energy and Minerals Section, September 1979); Department of Energy, Mines and Resources, Electric Power in Canada - 1979 (Canada: Electrical Section - Energy Policy Sector, 1980); "Canada -Still Planning for a Strong 1980," Electrical World 1980 Statistical Report, 5 March 1980.

TABLE B.1.1 COMPARISON OF GENERATING CAPACITY MIX, BY PROVINCE, 1977 and 1989 (PERCENT)

Province	Coal	Oil	Gas	Nuclear	Hydro	Turbine	Internal Combustion
P.E.I.							
1977	0.00	57.89	0.00	0.00	0.00	35.96	6.14
1989	0.00	57.89	0.00	0.00	0.00	35.96	6.14
Nfld.							
1977	0.00	4.54	0.00	0.00	92.01	2.48	0.96
1989	0.00	6.31	0.00	0.00	90.05	2.72	0.92
N.S.							
1977	22.70	51.37	0.00	0.00	11.14	14.73	0.07
1989	47.66	28.88	0.00	0.00	15.15	8.28	0.04
N.B.							
1977	6.22	60.63	0.00	0.00	31.81	1.11	0.24
1989	10.53	40.26	0.00	20.16	28.16	0.74	0.16
Que.							
1977	0.00	4.28	0.00	1.39	92.66	1.21	0.46
1989	0.00	1.60	0.00	1.69	85.03	11.39	0.29
Ont.							
1977	34.20	9.08	5.22	17.61	31.74	2.11	0.05
1989	29.80	6.06	3.49	37.82	21.38	1.41	0.03
Man.							
1977	12.67	0.00	0.00	0.00	86.00	0.76	0.57
1989	10.10	0.00	0.00	0.00	88.84	0.61	0.46
Sask.							
1977	45.28	0.00	19.15	0.00	28.04	7.43	0.10
1989	65.10	0.00	12.21	0.00	17.89	4.74	0.06
Alta.							
1977	58.69	0.00	19.71	0.00	16.10	4.69	0.81
1989	75.07	0.00	12.51	0.00	8.66	3.32	0.43
B.C.							
1977	0.00	0.00	12.64	0.00	82.13	4.02	1.20
1989	14.37	0.00	6.70	0.00	75.72	2.57	0.64
NATIONAL							
1977	18.82	7.84	5.30	6.37	58.40	2.78	0.47
1989	19.74	4.56	3.14	12.16	54.80	5.28	0.31

TABLE B.1.2 COMPARISON OF GENERATION MIX, BY PROVINCE, 1977 and 1989 (PERCENT)

Province	Coal	Oil	Gas	Nuclear	Hydro	Turbine	Internal Combustion
P.E.I.							
1977	0.00	66.84	0.00	0.00	0.00	32.37	0.79
1989	0.00	43.36	0.00	0.00	0.00	48.97	7.66
Nfld.							
1977	0.00	0.67	0.00	0.00	99.19	0.07	0.07
1989	0.00	0.82	0.00	0.00	99.05	0.07	0.06
N.S.							
1977	10.40	58.64	0.00	0.00	19.14	11.81	0.01
1989	49.48	8.51	0.00	0.00	33.47	8.54	0.01
N.B.							
1977	7.56	33.48	0.00	0.00	57.99	0.94	0.03
1989	10.04	10.97	0.00	21.98	56.94	0.04	0.02
Que.							
1977	0.00	0.00	0.00	0.37	99.55	0.04	0.04
1989	0.00	0.00	0.00	0.49	99.05	0.44	0.03
Ont.							
1977	18.90	0.98	0.23	28.47	51.33	0.09	0.01
1989	12.19	0.62	0.14	54.18	32.80	0.06	0.00
Man.							
1977	5.50	0.00	0.00	0.00	94.40	0.03	0.06
1989	3.41	0.00	0.00	0.00	96.53	0.02	0.04
Sask.							
1977	55.72	0.00	0.79	0.00	43.17	0.30	0.01
1989	71.05	0.00	4.32	0.00	24.40	0.17	0.06
Alta.							
1977	61.51	0.00	11.07	0.00	27.12	0.21	0.09
1989	81.94	0.00	5.82	0.00	12.08	0.12	0.04
B.C.							
1977	0.00	0.00	0.51	0.00	99.21	0.16	0.12
1989	7.28	0.00	0.23	0.00	92.35	0.09	0.05

Quebec, Manitoba, Newfoundland and British Columbia, hydro generation maintains its dominant role, accounting for well over 90 percent of generation in each of these provinces in both 1977 and 1989. Because of the expected rise in the price of gas and oil, the utilization of steam units based on these fuels may fall considerably in some provinces.

The U.S. Sector

Electric utility generation in the U.S. by energy source is summarized for the year 1979 in Table B.1.3. Roughly 50 percent of the electricity generated in 1979 was supplied by coal-fired units. The remaining 50 percent was supplied by oil, natural gas, hydro and nuclear in roughly equal proportions. Total U.S. electric generation in 1979 was 2 248 billion kilowatt-hours, an increase of roughly 2 percent over the preceding year (1).

TABLE B.1.3 U.S. ELECTRIC UTILITY GENERATION BY ENERGY SOURCE (1979)

Energy Source	Generation (billion kilowatt-hours)	% of Total Generation
Coal	1 075	47.8
Petroleum	304	13.5
Natural Gas	330	14.7
Hydro	280	12.5
Nuclear	255	11.3
Geothermal and Other*	4	0.2
Total	2 248	

Source: Reference 1.
*Includes production from plants that consume wood, refuse, and other vegetable fuels.

Production of electricity by coal-fired units in the U.S. has been steadily increasing since 1960*. Coal use in the utility sector has more than doubled since 1964 (1). The total amount of coal delivered to electric utility plants in the first six months of 1980 was 295.4 million tons (2). Over 60 percent of this coal went to 11 states:

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*With the exception of 1978, when coal use was roughly 1 percent less than in 1977.

Ohio (26.1),*, Texas (22.0), Pennsylvania (20.9), Illinois (19.1), Indiana (18.2), West Virginia (15.4), Tennessee (13.2), Kentucky (12.0), North Carolina (11.2), Michigan (11.1), and Missouri (10.8) (2). Through a combination of policy initiatives instituted by the Federal government, coal use in the U.S. utility sector is expected to increase substantially over the next few years.

UTILITY GENERATION BY REGION

U.S. utility capacity and generating rate for fossil-fuel-fired power plants in 1978 is summarized by state and region in Table B.1.4. The percentage change in generating rate (1977 vs. 1978) and percentage generation by fuel is also shown in Table B.1.4. From this table it is evident that the greatest quantities of coal used in the utility sector are in the following regions (in decreasing order): east north central, south Atlantic, east south central, west north Central, and middle Atlantic states. U.S. totals listed at the bottom of Table B.1.4 show that coal constitutes 61.2 percent of total electric generation in fossil-fuel-fired plants (3) (47.8 percent when nuclear, hydro, and geothermal are considered).

Electric generation by fossil-fuel plants is broken down by state and region in Table B.1.4 for areas of the country close to the U.S./Canadian border. From this it can be seen that the greatest amount of coal use occurs in the following states**: Ohio (103.2), Pennsylvania (83.2), Illinois (63.4), and Indiana (59.5) (3). In each of these states, coal accounted for more than 80 percent of the electricity generated in 1978.

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*Numbers in brackets are million tons delivered to utility plants in each state.

** The numbers in brackets are thousand megawatt-hours of coal-fired electric generation.

TABLE B.1.4 SUMMARY OF CAPACITY AND GENERATION FOR FOSSIL-FUEL-FIRED PLANTS BY STATE AND REGION, 1978 (3)

	Fossil Generation					
State/Region*	Capacity (MW)	(1000 MW-H)	(% Change Year Ago)	Coal	Oil	Gas
Connecticut	3 506	11 537	+4.4	0	100	0
Maine	717	930	+29.3	0	100	0
Massachusetts	6 437	30 095	+4.0	0	99.6	0.4
New Hampshire	1 052	3 840	-4.6	50.5	49.5	0
Rhode Island	242	551	-1.1	0	100	0
Vermont	30	14	-72.5	64.3	21.4	14.3
New England Total	11 984	46 967	+3.6	4.1	95.6	0.2
New Jersey	5 967	21 093	-3.7	26.2	73.5	0.2
New York	17 613	62 206	-3.3	22.3	77.6	0.3
Pennsylvania	23 013	97 767	+1.8	85.1	14.9	0.2
Mid-Atlantic Total	46 593	181 066	-0.7	56.7	43.2	0
Illinois	21 059	71 696	+2.5	88.4	9.5	2.1
Indiana	15 043	61 407	-1.7	96.9	2.7	0.4
Michigan	13 982	58 709	+5.8	80.6	17.6	1.8
Ohio	23 858	105 021	-2.9	98.3	1.6	0.1
Wisconsin	6 251	22 204	-3.8	96.7	2.0	1.3
East North Central Total	80 193	319 037	0	92.4	6.6	1.0
Iowa	4 299	14 812	+8.0	96.2	0.5	3.4
Kansas	5 903	22 938	+18.0	54.1	9.2	36.6
Minnesota	4 682	19 424	-6.3	97.0	2.9	0.1
Missouri	10 982	43 520	-2.3	95.1	1.3	3.6
Nebraska	1 541	5 911	+2.2	78.9	7.8	13.4
N. Dakota	1 636	8 814	+6.4	99.7	0.3	0
S. Dakota	546	2 838	+15.3	97.8	2.1	0
West North Central Total	29 589	118 257	+2.9	87.2	3.3	9.5
South Atlantic Total	72 478	302 322	+0.2	67.6	27.7	4.7
East South Central Total	38 002	156 694	-1.5	89.9	7.5	2.5
West South Central Total	69 515	272 627	+7.4	13.8	9.5	76.7
Mountain State Total	21 618	100 001	-5.1	82.0	4.5	13.5
Pacific State Total	23 445	94 955	-22.2	6.5	62.6	30.8
United States Total	393,417	1,591,930	-0.7	61.2	21.0	17.9

*Regions closest to the U.S./Canadian border are broken out by state
Source: Reference 3.

REFERENCES

1. DOE's Energy Information Administration, "Annual Report to Congress, 1979", Volume Two, Report No. DOE/EIA-0173(79)/2.

2. DOE's Energy Information Administration, "Energy Data Report: Coal Distribution, January-June 1980", Report No. DOE/EIA-0125(80/2Q), October 20, 1980.

3. National Coal Association, "Steam Electric Plant Factors, 1979", National Coal Association, 1130 Seventeenth St., Washington, D.C., 20036.

B.1.2 CONTROL TECHNOLOGIES

TECHNOLOGIES FOR CONTROLLING EMISSIONS FROM THERMAL GENERATING STATIONS

The emphasis in controlling emissions from fossil-fuel-fired power plants is shifting somewhat from local considerations to regional concerns regarding problems such as acid rain, visibility, and respirable particulates. In view of this, a reassessment of abatement methods is needed, aimed at determining which of the processes are most capable of accomplishing the degree of control needed from the regional viewpoint, from the standpoints of both control efficiency and cost effectiveness.

In general, the optimum process for controlling a given pollutant depends on the degree of control required. Processes that reduce emissions to an extreme degree are quite expensive and are usually not implemented unless the high efficiency is considered to be essential. On the other hand, techniques that cost less are not normally capable of a high degree of control.

The pollutants of concern are sulphur oxides (SO_2 and SO_3), nitrogen oxides (NO and NO_2, generally referred to as NO_x), and solid material carried in the gas stream (ash from the fuel, unburned carbon, and other non-gaseous particles--all generally referred to as "particulate matter"). Most of these come from the fuel itself, by reaction of sulphur and nitrogen compounds with oxygen supplied by the combustion air, and by burning out the combustible compounds leaving the ash as small solid particles. In addition, some NO_x is formed by reaction of nitrogen and oxygen in the combustion air.

The amounts of such pollutants vary with type of fuel, design and size of boiler, and capacity factor. Typical data are given in Table B.1.5 for a 500 MW unit. Although the tonnages listed are high, the concentrations in the flue gas are quite low because of the very large flue gas volume, which is composed mainly of carbon dioxide and water vapor; the 500 MW boiler in Table B.1.5 would produce about 60 000 tons of flue gas per day, at full power; at 60% capacity factor, this is equivalent to 13 million tons of flue gas per year.

The large amounts of pollutants evolved have led to regulations for reducing emissions. As might be expected from Table B.1.5, the main emphasis in the past has been on particulate matter, where coal is the fuel, because of the large amount involved; devices to collect and remove particulates from the gas stream have been required for a long time. Since 1971, sulphur oxide and nitrogen oxide emissions have been regulated in the U.S.. In Canada, recommendations for emission controls have been submitted to the provinces.

TABLE B.1.5 TYPICAL UNCONTROLLED EMISSIONS OF POLLUTANTS[a]

Fuel	Pollutant (tons per year)		
	Sulphur oxides	Nitrogen oxides	Particulates
Natural gas	--b	4 000	--b
Oil (1.0% sulphur)	15 000	4 800	1 100
Coal			
Low-sulphur (0.7%)	15 000	8 200	110 000
High-sulphur (4.0%)	88 000	8 200	110 000

a 500 MW boiler, 60% load factor. Levels given are fairly typical; in practice they vary over a wide range. Coal burned, about 1.1 million tons/year.

b Natural gas normally contains very little sulphur or ash.

Emphasis on nitrogen oxide control is just beginning, mainly in congested areas such as in Japan and southern California in the United States.

Sulphur oxides and particulates are removed from the gas stream by a variety of devices. (Sulphur oxide emissions can also be reduced by using low-sulphur fuel.) For nitrogen oxides, the general practice has been to reduce emissions by altering combustion conditions in the boiler in such a way as to reduce NO_x formation. Since this is only partially effective, there has been some use in Japan of devices to remove NO_x from the gas.

Emission Rates

In this sector, emission rates are routinely stated in terms relating to the heat input to the boilers. The range of emissions for the three pollutants varies widely, depending on the fuel characteristics and the boiler design.

SO_2	Canada	0 - 13 lb/10^6 Btu
	U.S.	0 - 8 lb/10^6 Btu
NO_x	Canada/U.S.	0.5 - 1.0 lb/10^6 Btu
Particulates*	Canada/U.S.	0.03 - 3.0 lb/10^6 Btu

*As presently controlled.

Sulphur Dioxide controls can be broadly classified as follows:

- Physical Coal Cleaning
- Flue Gas Desulphurization
- Low-Sulphur Fuel
- Fuel Desulphurization - Oil
  - Coal

Nitrogen Oxides controls can be classified as:

- Burner Modification
- Boiler Design and Operation
- Flue Gas Treatment

Particulate control is achieved as follows:

- Cyclonic cleaning
- Electrostatic Precipitator
- Baghouse

Definitions

"In use" technologies are those that have been demonstrated on a commercial scale and for which orders have subsequently been placed. "Available" technologies are those that have been demonstrated but not yet installed or ordered to any significant extent. "Emerging" technologies are those in the research and development stages that have been developed to the pilot-scale level.

A) Sulphur Dioxide Control

In the past, the main approach to sulphur oxide control in countries such as Japan and the U.S. has been the use of naturally occurring low-sulphur fuel. This is still the practice in Japan, but in the U.S. the recently enacted federal regulations now require a reduction in uncontrolled emissions for all new boilers burning oil or coal -- and pressure is growing to require such reduction for existing units. Several approaches can be used to attain the reduction, including fuel blending, fuel desulphurization, coal cleaning, coal conversion, desulphurization during combustion, and flue gas desulphurization (FGD).

a) Physical Coal Cleaning

For coal, part of the sulphur can be removed at relatively low cost by physical methods, that is, the coal is subjected to a treatment based on gravity differences to separate the crushed material. Since the heavier fractions contain much of the sulphur, some 10-30% of the sulphur can be removed fairly easily depending on the sulphur characteristics, among other things. A variety of methods are used, including washing, shaking and mineral concentration methods.

If more than 10-30% removal of the sulphur is required, physical cleaning becomes expensive. It can be combined with other methods to advantage if an intermediate degree of removal is acceptable and if the original pyrite sulphur content is extremely high. For 90% and higher removal of sulphur in the fuel, (10% or less left in the coal), as now required in the U.S. for new plants, other methods are more cost effective.

Cost: Physical coal cleaning is probably the most cost-effective method available for reducing SO_2 emissions if a high degree of reduction is not required. A TVA study shows a cost of $0.22 per lb of sulphur removed for cleaning and $0.237 per lb for limestone scrubbing (2000 MW, 3.5% S coal, 29-32% removal by cleaning, and 85% by FGD). Within the limits of accuracy of the estimates, the costs are thus about the same. There are certain more or less intangible benefits to cleaning, however, that are not counted in this comparison, and that should make cleaning the clear choice if 10-30% removal is acceptable.

For lower-sulphur coals, the cost of cleaning increases rapidly with decrease in coal sulphur content. For example, at 0.7% sulphur, the cost per lb of sulphur removed is $1.88, as compared to $0.89 for FGD.

b) Chemical Desulphurization of Coal

A large amount of experimental effort has been expended on methods for desulphurizing coal by chemical means. The process types vary widely, from simple leaching by chemical solutions to methods that involve dissolution of the coal and reconstitution of the solids. The last of these, generally called Solvent Refined Coal (SRC), borders on a coal conversion process and is usually classed as such. However, it is also a process for cleaning the coal of ash and sulphur and producing a clean solid fuel with characteristics much like the original coal but with much reduced polluting potential.

Although much development work on chemical coal cleaning (CCC) has been carried out, there is as yet no commercial use. SRC, sometimes called a synthetic fuel, is probably the closest to commercializaton. One module of a commercial-size plant is to be funded by the U.S. DOE, with final designs due by mid-1980 and start-up planned for

The developers plan to expand the facility to commercial size and have it operating by 1990; the capacity will be 30 000 tons per day (five 6 000 tpd modules).

All the other CCC methods are only at the bench or pilot-plant scale of development.

Process Evaluation: Chemical coal cleaning has the same problem as physical cleaning--difficulty in getting a high degree of removal without incurring high cost. Although most of the chemical cleaning methods will do better than physical cleaning processes in removing both pyritic and organic sulphur, especially the latter, overall removal is usually considered to be in the range of 60 to 75%. SRC does better than the others because the hydrogenation promotes sulphur removal; the process probably can make 85% removal at a cost competitive with wet scrubbing, but 90% or higher removal of sulphur is a difficult objective.

Cost: Because of the chemical steps involved, chemical coal cleaning costs considerably more than physical cleaning methods. The cost per lb of sulphur removed ranges from $0.253 to $0.44. In contrast, the estimated cost for FGD, which was assumed to remove 85% of the SO_2 as compared to 59 to 73% for the CCC processes, is estimated at $0.237 per lb of sulphur.

Various cost estimates have been published for SRC. EPRI estimates indicate a cost of about $4.50 per million Btu for SRC, which corresponds to about $113 per ton of Eastern coal (at 12 500 Btu/lb). This is considerably higher than the levels estimated for use of raw coal plus scrubbing, which are $25 to $30 per ton for the coal and $10 to $15 per ton for the scrubbing. However, SRC has several advantages such as low ash content that give other savings, thus making the cost comparison quite complicated. At the best, the process does not seem likely to be competitive with flue gas scrubbing at 90% and higher removal requirement.

Reliability: It should be noted that the cost comparison between CCC and FGD is affected in a major way by how the reliability problem is handled. CCC can be considered completely reliable to the power plant operator on the basis that the CCC plant will maintain a stockpile of product to assure an uninterrupted supply. For FGD, however, full reliability cannot be assumed and in fact has not been attained in most operating systems. The same criticism applies of course to all other components of the power train, from fuel input to the generator output.

c) Desulphurization of Oil

Oil desulphurization is a well-developed technology, used widely in several countries. The method has been used extensively in Japan to reduce SO_2 emissions.

The residual sulphur in the treated oil is usually in the order of 0.2 to 0.5% but a higher degree of desulphurization is feasible. The situation is similar to coal cleaning in that the cost increases with the degree of desulphurizaton. Japanese data show an increase from $16/kL to $27/kL when increasing from 70% to 97% sulphur removal, compared to an equivalent increase from $16 to $19 for a similar improvement in efficiency for flue gas desulphurization.

d) Flue Gas Desulphurization -- Dry Processes

One of the newer developments is injection of a lime slurry into a spray drier concurrently with the flue gas. The lime reacts with the SO_2 to form a dry, solid product that is collected downstream in an electrostatic precipitator or fabric filter (usually called a baghouse). The main advantages are relative simplicity of equipment, production of a dry waste material rather than a wet sludge, lower energy requirement, and possibly lower maintenance and better reliability. The drawbacks are need for lime (more expensive that limestone) and difficulty in getting a high degree of removal. The latter effectively limits the process to low-sulphur coal.

Only pilot plant data are available but enthusiasm for the process has led utilities to contract for several installations in the U.S. There is some indication from bidding situations that the process does not have as much cost advantage as expected.

Cost: Published cost estimates indicate a lower cost for the spray drier process, in the order of 15% or so. Basin Electric, for example, estimated the capital cost at Antelope Valley to be $129/kW (including particulate removal) for a dry system as compared to $145/kW for wet scrubbing (limestone). At Laramie River, the estimates were $100/kW and $121/kW, respectively. The capital costs of dry processes at this time are uncertain. Because of the relative simplicity there may be some cost advantage.

Operating cost depends mainly on what is assumed for operating labor and maintenance plus the amount of lime required and the price margin over limestone. TVA estimates show lower direct costs (including absorbent) for wet scrubbing but when items such as overhead and capital charges (which depend on capital cost) are added, the annual revenue required may be less for dry processes than for wet systems.

e) Flue Gas Desulphurization -- Wet Scrubbing

Scrubbing the flue gas with a limestone slurry has become the basic FGD process. It has been available commercially for over 10 years, limestone is the least expensive sulphur absorbent available, and no competitive process has been demonstrated to be more cost effective. The main drawbacks have been corrosion/erosion in the scrubbers, unreliability of the very large slurry circulation pumps, and production of a wet, difficult-to-handle sludge. Moreover, there has been in the past some trouble with system availability, particularly with high-sulphur coal.

Progress has been made in all these areas but the problems in some plants are still not completely resolved. Small amounts of promoters such as magnesium or adipic acid are sometimes added to the reagent; tests have shown these to be often effective in raising SO_2 removal efficiency. Spare equipment is being generally installed as a means of ensuring reliability.

There is a wide range in capital costs owing to site-specific considerations, and to variation in the bids from different vendors. Lime has some operating advantages over limestone and is sometimes used.

Lime-limestone scrubbing is widely used in all areas -- Japan, the U.S., and West Germany -- where SO_2 emission reduction is required. In the U.S., the capacity currently operating on utility boilers is over 19 000 MW and 53 000 MW more is under construction or planned. It is estimated that nearly 160 000 MW will be in operation by 1990.

One of the scrubbing process variations is the so-called "double alkali" process. The advantages of the process are very high removal efficiency and better scrubber operation because of the clear solution, avoiding scaling of the scrubber internals.

Sludge Disposal

Lime-limestone scrubbing produces waste solids (mainly calcium sulphite) with very undesirable properties -- difficult to dewater and incapable of supporting much weight when placed in the waste disposal area. Moreover, potential leaching of constituents is regarded by environmental agencies as a serious problem.

Dewatering and strength can be improved to a considerable extent by forced oxidation -- bubbling air through the scrubber slurry to oxidize calcium sulphite to calcium sulphate (gypsum), a material that precipitates as large crystals easier to dewater and stronger when placed in a waste pond or landfill. There is a current trend to specifying forced oxidation when purchasing scrubber systems.

The leaching problem is vague and ill-defined. Calcium sulphite and sulphate are relatively innocuous but regulatory authorities express concern about the leaching of metal compounds (selenium, arsenic, mercury, and others) from the residual fly ash collected in the scrubber and present in the sludge.

f) Flue Gas Desulphurization — Recovery Processes

Recovery of the SO_2 in power plant flue gases as a useful material has been a research goal for several decades. Numerous companies have seen this as a promising business venture and have expended large sums in development. Various agencies and institutes have also taken part, including TVA, EPA, DOE, and EPRI in the U.S., Bergbau Forschung in Germany, and various groups in Japan.

The results of all this work have not been very promising. In Japan there are only four installations on utility boilers, totalling a little over 500 MW. There are also about 25 units on industrial boilers and other industrial operations with a total gas flow equivalent to about 2 500 MW. In the U.S., two utilities have installed recovery processes on a commercial basis; the total capacity is about 2 500 MW.

Process Description: There are dozens of recovery processes, in various stages of development. Only the more significant ones will be summarized.

- Wellman-Lord. The gas is scrubbed with sodium sulphite solution and the resulting sodium sulphite-bisulphite heated to evolve a rich stream of SO_2, convertible either to sulphuric acid or elemental sulphur. The process is used by New Mexico Public Service and NIPSCO in the U.S., and by Chubu Electric in Japan.

- Magnesia scrubbing (Chemico, United Engineers). The gas is scrubbed with MgO slurry to form $Mg(HSO_3)_2$ which is then treated with MgO to precipitate $MgSO_3$. The sulphite is dried, calcined to evolve a rich stream of SO_2, and the SO_2 converted to sulphuric acid. Philadelphia Electric is installing the process at two stations and TVA plans an installation at the Johnsonville station.

- Rockwell. Sodium sulphite produced in a spray drying process is reduced to sodium sulphide in a furnace and the resulting melt treated with water and carbon dioxide to evolve a rich stream of H_2S, convertible to sulphur by the Claus process. The method has the advantage that coal can be used as the reducing agent whereas the other methods require either natural gas or expensive activated carbon. The process is being tested in a 100 MW facility at Niagara Mohawk's Huntley station.

Cost: A major drawback to recovery processes is relatively high cost. Complicated process flowsheets, absorbent losses, and high energy requirements all contribute to a high cost level.

One of the items contributing to high cost is the energy requirement. The following levels have been reported.

Process	Energy requirement, % of boiler energy input with no control
Wellman-Lord (sulphur as product)	12-25
Magnesia scrubbing	5-10
Limestone scrubbing	1.5-3

g) Coal Gasification (Combined Cycle)

Another approach is production of low Btu gas by coal gasification, removing ash and sulphur, and burning the clean gas in a combined-cycle operation (use of a gas turbine and boiler in series to improve energy utilization). In this case, the increase in energy efficiency is the major objective in addition to desulphurization, and thereby complicates estimation of the sulphur removal cost. Most estimates show a cost reduction of 15% or so by the combined cycle route (based on cost per kW-h), compared to a conventional boiler with FGD, but commercialization is probably 15 to 20 years away. Moreover, the cost of new processes tends to go up as development work progresses.

h) Fluidized-Bed Combustion

The most promising method in emerging technology is fluidized-bed combustion. In the fluid-bed process, air blown up through a bed of fine coal and limestone burns the coal in a suspended state and produces steam in water tubes submerged in the bed. The limestone absorbs the SO_2. Capital cost for SO_2 removal should be low because no separate reactor is needed. The main drawback is difficulty in reaching a high level of SO_2 removal without using an inordinate amount of limestone and hence much increased waste production. To get 90% removal, some two to four times as much limestone is required compared to limestone wet scrubbing.

Estimation of sulphur control cost for fluidized-bed combustion is complicated by the fact that reduced boiler cost is an objective as well as sulphur removal. Proponent estimates generally show a saving of 10 to 15% per kW-h as compared to a conventional power plant equipped with wet scrubbing; others show the two about even. Commercialization for use in power plants is probably 10 to 20 years away.

Cost Factors: Like coal gasification, most cost estimates for FBC show some 10 to 15% lower cost as compared to a conventional system fitted with FGD. Most such estimates have been published by proponents; in more recent cost comparisons by TVA, it was concluded that although FBC (atmospheric and pressurized operation) shows a potential saving of 9 to 14% "when uncertainties are included, the estimated cost of electricity for the three alternatives is so close that all are considered to be within the competitive range for further consideration."

It should be noted that the FBC approach was favored by some of the assumptions in the TVA study, mainly the higher energy efficiency for FBC and the relatively high energy penalties assigned to conventional systems plus FGD. For example, it was assumed that atmospheric FBC has an energy efficiency of 35.8% as compared to 31.8% for conventional boilers. In contrast, a British study shows 36.6% for FBC and 37.1% for conventional boilers. The comparative cost of FBC and conventional operation cannot be calculated accurately at the present time.

Process Choice: The recommendations in the following table are made for process choice at different required levels of emission reduction. It should be noted that these are only approximate and that site-specific conditions could well change the ranking. The rankings are judgmental in nature, based on a subjective evaluation of factors such as cost, commercial viability, control efficiency, and process reliability.

Removal efficiency level, %	Process listing
Higher than 90%	1. Double alkali 2. Limestone scrubbing with promoters 3. Coal gasification (combined cycle)[a] 4. Recovery processes
90%	1. Limestone scrubbing with promoters 2. Limestone scrubbing 3. Double alkali
50-90% (high-sulphur coal)	1. Limestone scrubbing, (with physical coal cleaning where upper limit on SO_2 emissions applies)

	2. Fluidized bed combustion[a]
	3. Chemical coal cleaning[a]
	4. Low-sulphur fuel substitution (not a sulphur removal process)
	5. Limestone injection through modified burner[b]
50-90% (low-sulphur coal)	1. Spray drier process
	2. Limestone scrubbing
Below 50%	1. Physical coal cleaning (highly variable effectiveness due to coal properties)
	2. Blending with low-sulphur coal

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[a] When and if developed.

[b] Ranking due to current status of development.

B) Nitrogen Oxide (NO_x) Control

The alternatives for nitrogen oxide control are boiler operation changes, combustion equipment modifications to reduce NO_x formation, and flue gas treatment (FGT) to remove it from the gas. Boiler operation changes introduce hazards especially with coal, and are not popular. Combustion equipment modification is much less expensive than FGT, and is used both in the U.S. and Japan. In situations where the regulations have become so stringent that combustion modification is not capable of achieving the required emission reduction, flue gas treatment is employed. It has been used on full-scale Japanese oil-fired units, and is being evaluated at pilot scale on U.S. coal-fired boilers.

a) Combustion Modifications: In the U.S. and Canada, combustion modification (CM) is the most common method of NO_x reduction. NO_x can be reduced by injecting the combustion air in two stages, normally by reducing air flow to the burner and injecting the remainder through "overfire" air ports in the side of the boiler. "Low-NO_x" burners that accomplish staged conditions within the burner flame have also been developed.

Staged combustion is the most cost effective of the methods but normally only reduces emission by 15-25%. Gas recirculation is more expensive but is quite effective for gas or oil, giving an emission reduction up to 50%. Low-NO_x burners are effective and are often used in Japan in combination with the standard type of staged combustion and with gas recirculation. Combustion modification has given very low NO_x emissions in

Japanese tests, 100 ppm with coal and 50 ppm with oil -- a reduction of 75 to 80% compared to uncontrolled emissions. However, an advanced degree of combustion modification can cause slagging in the boiler and corrosion of heat transfer surfaces.

Typical emission limits achievable using combustion modification techniques and their associated capital costs are:

Low Excess Air	0.9 lb $NO_x/10^6$ Btu	\$0.
Staged Combustion	0.7 "	\$2-3/kW
Low-NO_x Burner	0.4-0.5 "	\$2-10/kW

Emissions are based on coal-fired units emitting 1.0 lb/10^6 Btu when uncontrolled.

Since NO_x emissions are complex functions of boiler design and operation, and also fuel characteristics, emissions vary widely, (e.g., for wall-fired units, the range is generally 0.7 to 1.3 lb NO_x per million Btu input). This wide range of uncontrolled emissions leads to uncertainty on controlled emission rates when combustion modification is employed.

The capital costs are dependent in part on site-specific variables, and the accuracy of the costs quoted is not better than -10% to +30%.

b) Flue Gas Treatment: The leading method is injection of gaseous ammonia to reduce NO_x to harmless nitrogen. Operation without a catalyst requires very high temperature and removal is limited to about 35 - 40%. With a catalyst, 90% or higher is feasible but 80% gives much less operating difficulty and may be the upper practicable limit for high-sulphur coal.

c) Process Choice: The situation is similar to that for other pollutants — process choice depends on the degree of control required.

NO_x removal efficiency level, %	Process ranking
90% or higher	1. Catalytic reduction* with more than the normal amount of catalyst, preceded by combustion modifications
50-80%	1. Catalytic reduction with a normal amount of catalyst 2. Combustion modification (all types) followed by non-catalytic reduction (ammonia injection without catalyst)

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* This technology has not been proven on coal-fired boilers.

	3. Combustion modification alone (for low part of range so as to minimize boiler problems) 4. Low-NO_x burners[b]
Below 30%	1. Staged combustion[a] 2. Low-NO_x burners[a] 3. Gas recirculation (except for coal)[a]

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[a] Used in combination with others if necessary to achieve the required reduction level.

[b] Under development.

C) Particulate Matter Control

a) Precipitation and Filtration: Electrostatic precipitation is the basic method in the power generation industry for removing particulates originating as ash in the fuel. However, there is a trend toward using fabric filters (baghouses) in the U.S. as a means of attaining the very stringent emission standard adopted recently for new boilers.

b) Wet Scrubbing: The limited ability of wet scrubbers to remove very fine particulates makes their use questionable to meet the new regulations in the U.S., an unfortunate situation because scrubbers can remove the bulk of the coarse particulates at very low cost. In a new development, a wet precipitator after the scrubber removes the fine particulates.

c) Process Choice: For the current new source performance standards in the U.S. (0.03 lb/10^6 Btu), baghouses are probably superior for low-sulphur coal because the ash does not precipitate easily. For high-sulphur fuel, the situation is not clear; more experience with baghouses is needed. For a standard such as 0.1 lb/10^6 Btu, precipitators are more cost effective.

B.1.2.1 Technologies in Use

SO_2 Reduction

a) Physical coal cleaning

b) Blending with low-sulphur fuel

c) Oil desulphurization
d) Flue gas desulphurization

NO_x Reduction

a) Flue gas recirculation (FGR) (gas-fired units)
b) Low excess air
c) Staged combustion

B.1.2.2 Available Technologies (see definition in B.1.2)

SO_2 Reduction

a) Magnesium oxide scrubbing remains to be demonstrated on a full-scale power station with an acceptable degree of reliability. Anticipated costs are likely to be higher than limestone, though experience is extremely limited.
b) Lime/limestone scrubbing with chemical promoters, e.g., adipic acid.

Nitrogen Oxide Reduction

a) Low-NO_x burners
b) Flue gas treatment (FGT)

Performance of NO_x Reduction Techniques

FGR is used now for superheat control and has some beneficial effects on NO_x reduction. Generally, it is evidently not a favored technique. Its costs are indeterminate. Low excess air may be applicable and costs nothing, but operators may resist it because of safety problems with pulverized coal. Staged combustion is available but possibly may cause corrosion problems.

Low-NO_x burners are available at $1-10/kW, depending on size and ease of replacement of existing burners.

B.1.2.3 Emerging Technologies

SO_2 Reduction

a) Fluidized-bed combustion
b) Fuel gasification
c) Gasification with combined cycle operation
d) Pressurized fluidized-bed combustion
e) Coal liquefaction, direct (SRCI and SRCII) and indirect (e.g., SASOL)
f) Limestone injection with multi-stage burner, (LIMB process)

NO_x Reduction

a) Ammonia injection
b) Advanced low-NO_x burners

Second generation low-NO_x coal burners, projected to be capable of NO_x emission of 0.2-0.3 lb per million Btu, will soon begin commercial demonstration. It is projected that these advanced low-NO_x burners may be commercially available in the 1983-85 period.

Flue gas treatment processes have been evaluated at pilot scale for coal applications in Japan and the U.S. The results of the pilot-scale testing have shown that the long-term NO_x removal may be affected by the nature of the fly ash. More effort to evaluate the impact of coal and fly ash type on the performance of flue gas treatment processes is needed.

B.1.3 ALTERNATIVE PRODUCTION PROCESSES

1. Hydro
2. Nuclear
3. Magnetohydrodynamics
4. Tidal Power
5. Solar Power
6. Wind

The last four in this group are not thought likely to make any significant contribution to commercial electric power production capacity in the next twenty years, except in special circumstances for very limited markets.

B.2 NON-FERROUS SMELTERS

B.2.1 Description of the Non-Ferrous Smelting Sector

Canada

The large smelter sources of SO_2 in Canada are estimated to emit about 2.7 million tonnes per year when operating at full capacity. In 1980, the emissions are estimated to be only 2 million tonnes largely because of below capacity operations related to depressed metal markets. A brief presentation of smelter statistics is given in Tables B.2.1 and B.2.2. Two zinc smelters (CEZ at Valleyfield, Quebec and Texas Gulf at Timmins, Ontario) and a lead smelter (Brunswick Mining and Smelting at Belledune, N.B.) already control 85 to 90% of their sulphur input, and as a result are not considered major emissions sources of SO_2 for the purpose of this study.

United States

In the United States, two distinct situations exist regarding sulphur emissions from non-ferrous metals production. There are 16 copper smelters, 6 lead smelters, and 8 zinc smelters (some of which have recently closed or are expected to close). In the eastern U.S., there are four primary zinc smelters and two primary copper smelters. These smelters have low SO_2 emissions because of the nature of the production processes and controls employed and are not included as major emission sources of SO_2 for the purpose of this study. The major non-ferrous smelting capacity is located in the western U.S. with the largest concentration in the Arizona-New Mexico area (see Figure B.2.1 and Table B.2.3). It is not known whether these sources contribute to the eastern acid rain problem.

B.2.2 Control Technology

Introduction

Non-ferrous smelters are, in principle, amenable to SO_2 emission control using technologies that are available. Acid plants and liquid SO_2 production are considered proven and, in most cases, affordable control approaches for strong SO_2 off-gas streams. The major issue here involves the availability of affordable technology for control of weak stream SO_2 emissions. There are three approaches to solving the weak SO_2 problem:

- flue gas scrubbing

TABLE B.2.1 GENERAL DESCRIPTION OF NON-FERROUS SMELTER SECTOR - PRESENT CONDITIONS

Smelter	Location	Processed Used	Capacity	SO_2 Emission Rates
Hudson Bay Mining and Smelting Co. Limited	Flin Flon, Manitoba	Cu-roasting (multiple hearth roasters), reverberatory furnace smelting, converting, anode casting	180 tonnes blister Cu per day	Current Manitoba control order 800 tonnes per day average monthly mean
		Zn-roasting (multiple-hearth roasters), electrowinning	230 tonnes refined Zn per day	
INCO Limited	Thompson, Manitoba	Ni-roasting (fluid-bed roasters), electric furnace smelting, converting, refining	130 tonnes refined Ni per day	Current Manitoba control order 1130 tonnes per day
INCO Limited	Copper Cliff, Ontario	Ni-roasting (multiple-hearth roasters), reverberatory furnace smelting, converting, refining	430 tonnes Ni per day in various forms	
		Cu-flash smelting, converting, refining	400 tonnes per day refined copper	Current legislation limits emission to 2270 tonnes per day
		Iron Ore Processing-pyrrhotite roasting (fluid-bed roasters), leaching, sintering	2200 tonnes per day iron ore, 20 tonnes per day Ni	230 tonnes per day under current legislation
Falconbridge Nickel Mines Limited	Sudbury, Ontario	Ni/Cu-roasting (fluid-bed roasters) electric furnace smelting, converting	130 tonnes per day Ni, 70 tonnes per day Cu	420 tonnes per day under current control order
Noranda Mines Limited, Horne Division	Noranda, Québec	Cu-green charged reverberatory furnace smelting, converting - Noranda continuous smelting furnace - anode Cu shipped to CCR, Montreal	540 tonnes per day Cu	1570 tonnes per day
Noranda Mines Limited, Gaspé Division	Murdochville, Québec	Cu-roasting (fluid bed-roasters), reverberatory furnace smelting, converting, anode furnace	230 tonnes anode Cu per day	230 tonnes per day

TABLE B.2.2 GENERAL DESCRIPTION OF NON-FERROUS SMELTER CONTAINMENT - SO_2

Smelter	Location	Sulphur Containment Process	SO_2 Containment	%[1]
Hudson Bay Mining and Smelting Co. Limited	Flin Flon, Manitoba	None installed	Nil	
INCO Limited	Thompson, Manitoba	None installed	Nil	
INCO Limited	Copper Cliff, Ontario	Liquid sulphur dioxide produced from copper flash furnace in copper-nickel smelter	365 tonnes per day	11
INCO Limited	Copper Cliff, Ontario	Sulphuric acid produced in contact acid plants from the iron ore recovery plant	1600 tonnes per day	85
Falconbridge Nickel Mines Limited	Sudbury, Ontario	Sulphurc acid produced in contact acid plant from fluid-bed roasters	525 tonnes per day	65
Noranda Mines Limited, Horne Division	Noranda Québec	None installed	Nil	
Noranda Mines Limited, Gaspé Division	Murdochville Québec	Sulphuric acid produced in contact acid plant from fluid-bed roasters	330 tonnes per day	60

[1] Percent SO_2 contained (sulphur contained to total sulphur input)

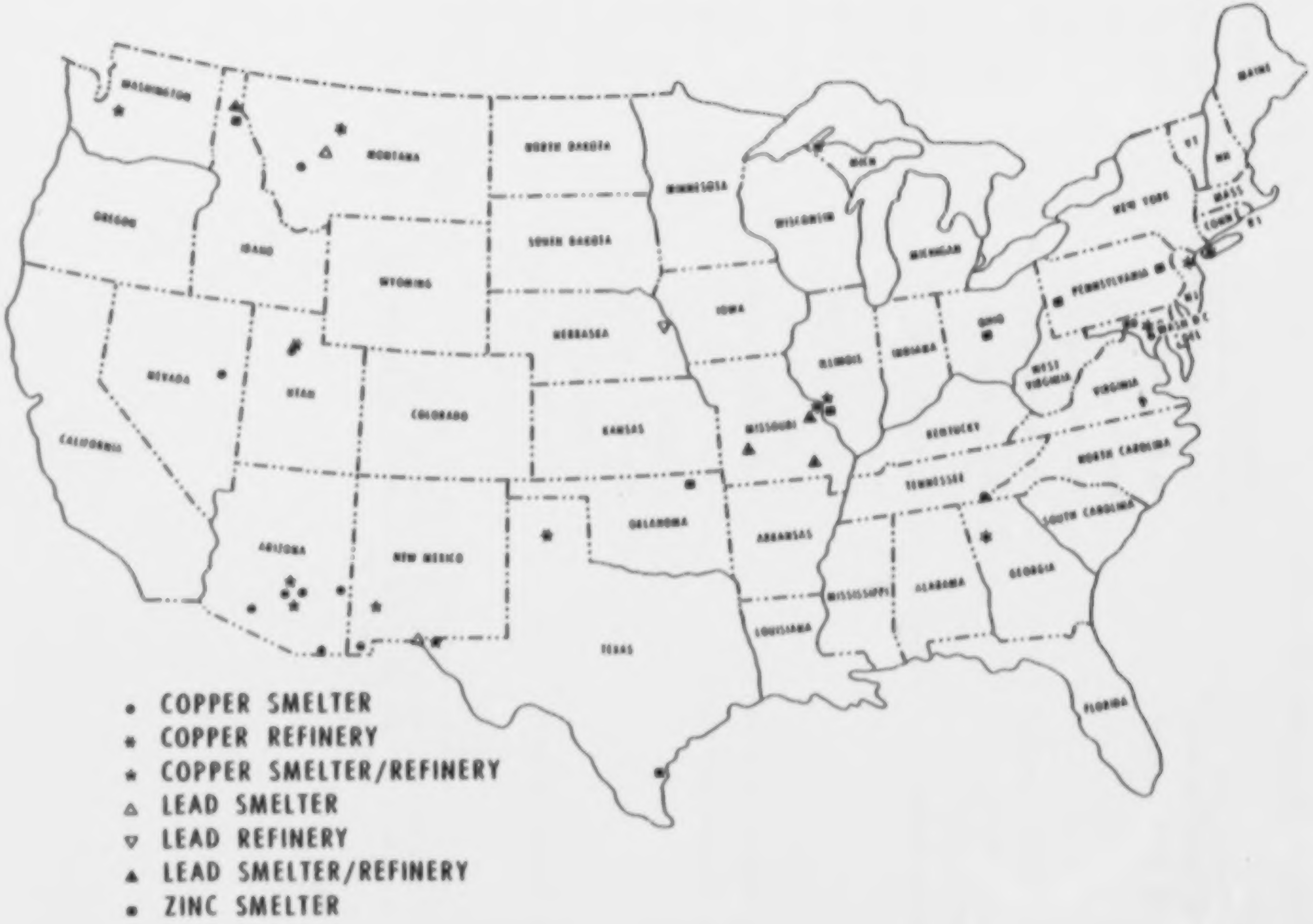

FIGURE B.2.1 PRIMARY U.S. NON-FERROUS SMELTING AND REFINING LOCATIONS

TABLE B.2.3 PRIMARY COPPER SMELTERS, 1979 (United States)

Company	Location	Annual capacity[a] (tonnes)
The Anaconda Company[b]	Anaconda, Montana	180 000
ASARCO, Incorporated	El Paso, Texas	104 000
	Hayden, Arizona	163 000
	Tacoma, Washington	91 000
Cities Service Company	Copperhill, Tennessee	20 000
Inspiration Consolidated Copper Company	Miami, Arizona	136 000
Kennecott Copper Corporation	Garfield, Utah	254 000
	Hayden, Arizona	73 000
	Hurley, New Mexico	73 000
	McGill, Nevada	45 000
Magma Copper Company	San Manuel, Arizona	181 000
Phelps Dodge Corporation	Ajo, Arizona	64 000
	Douglas, Arizona	115 000
	Hidalgo, New Mexico	127 000
	Morenci, Arizona	161 000
Copper Range Company	White Pine, Michigan	82 000
TOTAL		1 869 000

[a] Production of "blister" copper (99 percent Cu)

[b] Operations at this plant and the associated refinery at Great Falls, Montana were discontinued in December, 1980

- upgrading roaster and reverberatory furnace operations to produce a strong SO_2 gas stream for acid plant control
- alternative process technology which results in strong SO_2 gas streams for acid plant control or elimination of SO_2 formation.

In considering any approach, it is of paramount importance to consider the unique nature of each smelter. This uniqueness factor is determined by the nature of the ore concentrates and the metallurgy required to successfully treat these concentrates. It is these aspects that govern the selection of a metallurgical process for metal winning, and, in turn, the degree of sulphur containment. Each smelter requires an individual technical and economic assessment of feasibility.

In the selection of the production and control processes the following factors must be considered and evaluated:

a) amenability to SO_2 control
b) applicability of the production process to the concentrates to be treated (continuous smelting not applicable to concentrates with high lead or arsenic contents)
c) energy consumption, including the types and qualities of the energy used
d) capital and operating costs
e) amenability to improved industrial hygiene conditions
f) flexibility to changing conditions such as fluctuating levels of production, changes in composition of concentrates, etc.
g) creation and controllability of environmental problems whether air pollution, water pollution or solid waste disposal
h) recovery of primary metals and by-products

The control process for SO_2 emissions must be evaluated against the factors listed above, and must also include costs for pollution by-products disposal, whether as a marketable or throwaway by-product.

B.2.2.1 Control Techology In Use

The most common control method in use is conversion of SO_2 to marketable sulphuric acid. The cost of fixing sulphur in this way is shown in Table B.2.4.

The fixing of sulphur as marketable liquid sulphur dioxide is also practised. The cost is shown in Table B.2.5.

Both processes require a continuously-flowing gas of at least 4% SO_2. Therefore they are not normally applicable to gases from reverberatory furnaces or multi-hearth roasters. Gases from Pierce-Smith converters can be treated in this way provided that they can be scheduled to produce a fairly continuous stream or that a relatively large continuous higher concentration stream is available for mixing with the converter gases. Tight-fitting, water-cooled hoods would also have to be provided for the converter off-gases.

The cost of retrofitting smelter strong gas streams with an acid plant would be similar to that for new smelters except for the changes to existing metallurgical process equipment (e.g., revision to converter hoods as mentioned above).

Uncertainty of data base

The non-ferrous smelter capacities and the maximum SO_2 emission rates are based on validated data and the uncertainty factor would be about ± 5%. The costs of control technologies do vary from smelter to smelter depending on location of smelter (i.e., geographical remoteness), smelter configuration, age of smelter, availability and cost of services and materials such as electrical power, fuel, chemicals, etc. Thus the uncertainty of the capital and operating costs is greater and is estimated at ± 20% for capital costs and ± 15% for operating costs.

Factors such as varying interest rates, monetary exchange rates and non-technical constraints will further increase the cost uncertainties.

(i) Problems including waste disposal and energy aspects

A key problem that has to be addressed in any control action with regard to an existing non-ferrous smelter, and in some cases a new smelter, is the compatibility of the actual mineral concentrate to be smelted with the choice of smelting process and the control technology. The ideal, which can sometimes be achieved, is a completely contained or continuous smelting process which produces a reasonably steady flow of concentrated SO_2. The use of this ideal is currently limited to a few special cases where the level of trace elements (such as lead and arsenic) does not require a batch converter processing stage.

TABLE B.2.4 COST OF FIXING SULPHUR AS SULPHURIC ACID FROM SMELTER GASES USING SINGLE CATALYSIS ACID PLANT (EPS 3-AP-79-8)
($ CAN. June, 1979)

Basis for Estimates	Continuous Gas only	Variable Gas only	Continuous Gas Base Load with Variable Gases	
Production: t/day 100% H_2SO_4	530	530	530	1 070
Gases:				
Continuous smelter gas, i.e., from roaster, flash furnace, % SO_2	12	-	12	12
Variable gas, i.e., from converters, % SO_2	-	5 - 8	5 - 8	5 - 8
CAPITAL COST ($, June 1979 cost level)				
Single catalysis sulphuric acid plant[1]	11 880 000	19 499 000	14 799 000	22 363 000
Contingency @ 25%	2 970 000	4 875 000	3 700 000	5 591 000
Auxiliary equipment and services	1 485 000	2 437 000	1 850 000	2 795 000
Total Capital Cost	16 335 000	26 811 000	20 349 000	30 749 000
PRODUCTION COST ($/t H_2SO_4)				
Operating Cost:				
Supervision	0.54	0.54	0.54	0.26
Operating labour	1.06	1.06	1.06	0.60
Utilities[2]	1.61	2.86	2.01	1.97
Operating supplies[3]	0.28	0.28	0.28	0.28
Maintenance[4]	2.89	4.74	3.59	2.73
Indirect cost[5]	0.71	0.71	0.71	0.37
Subtotal	7.09	10.19	8.19	6.21
Contingency @10%	0.71	1.02	0.82	0.62
Total operating cost	7.80	11.21	9.01	6.83
Capital Charges:				
Amortization and Interest @ 15 years and 10%/yr	11.51	18.88	14.33	10.82
Total Production Cost	19.31	30.09	23.34	17.65

1. Includes engineering and construction overhead costs.
2. Includes natural gas, water and electric power.
3. Includes limestone for weak acid neutralization and other operating supplies.
4. @ 3.3%/year of total capital cost.
5. Includes property taxes, insurance, legal and technical counsel, etc.

t = tonne

TABLE B.2.5 COST OF RECOVERING LIQUID SULPHUR DIOXIDE FROM SMELTER GASES (EPS-3 AP-79-8)
($ CAN. June, 1979)

Basis For Estimates	Chemical Absorption Process (Asarco's Dimethyl Aniline Process)	Physical Recovery Process (Compression & Refrigeration)
Production:		
160 t/day liquid SO_2, corresponding to 56 000 t annually (assuming 350 operating days)		
Gas processed:		
smelter gases with 12% SO_2, cleaned in hot electrostatic precipitator		
CAPITAL COST ($June 1979 cost level)		
Liquid SO_2 plant[1]	7 103 000	6 314 000
Contingency @ 25%	1 778 000	1 578 000
Total Capital Cost	8 881 000	7 892 000
PRODUCTION COST	$/t SO_2	$/t SO_2
Operating cost		
Supervision	0.75	0.75
Operating labour	3.45	3.45
Utilities[2]	9.85	9.04
Operating supplies[3]	3.83	0.98
Maintenance[4]	7.13	6.34
Indirect costs[5]	1.36	1.36
Royalties[6]	0.63	--
Subtotal	27.00	21.92
Contingency @10%	2.70	2.19
Total Operating Cost	29.70	24.11
Capital Charges Amortization & interest @ 15 years and 10%/year	20.43	18.15
Total Production Cost	50.13	42.26

[1] Includes engineering and construction overhead costs.
[2] Includes steam, water and electric power.
[3] Includes chemicals and other operating supplies.
[4] @ 4.6%/year of total capital cost.
[5] Includes property taxes, insurance, legal and technical counsel, etc.
[6] Royalties payable for proprietary process.

t = tonne

The majority of the non-ferrous smelters currently controlling SO_2 emissions produce sulphuric acid as a by-product. It is anticipated that this trend will continue for some time. The disposal of the by-product sulphuric acid is likely to be a problem where a) the smelter is remote from sulphuric acid markets or b) existing sulphuric acid markets are already supplied with lower cost acid. In these cases the smelter acid can only be marketed, at a loss, which increases with the distance from market and the cost of competing acid. Non-market constraints such as international trade agreements, lack of adequate transportation facilities, etc., may prevent sale of acid in some areas. The marketing of the acid may impose costs on the smelter which increase the cost of control to a point where smelter closure is considered.

A related problem is the high cost and environmental problems associated with the neutralization of acid which cannot be marketed because of high cost or other reasons. The costs and environmental factors depend largely on the availability and cost of a reasonable source of limestone (not always close to smelter). The environmental problems of disposal of the neutralized acid are similar to those for the thermal power wastes.

Another factor in marketing smelter sulphuric acid is that the demand cycle for sulphuric acid may not coincide with the demand cycle for metals, raising the issue of the disposal of acid, that is excess to market demand at a time when metal demand is high.

Another waste disposal problem concerns the sludge produced in the cleaning of the SO_2-containing gases for acid production. This sludge often contains toxic metals which can create environmental problems if disposal measures are inadequate.

Energy Consumption

Energy consumption by SO_2 control technology in use varies from smelter to smelter. The increase in energy consumption due to sulphuric acid production is partly dependent on the strength of the SO_2 streams (the higher the SO_2 concentration, the lower the energy requirement) but is a small part of total smelter energy consumption.

Where new smelting processes are used to produce a gas amenable to SO_2 control in an acid plant, a net reduction in energy consumption usually results. For example, replacement of a multi-hearth roaster - reverberatory furnace operation with a flash furnace can lead to a net energy reduction of up to 65% of the roaster smelting system (including the acid plant energy increase).

B.2.2.2 Control Technology Available

The control technology discussed in Section B.2.2.1 (sulphuric acid and liquid sulphur dioxide plants) can be considered as available control technology for either new smelters or for retrofitting existing smelters. A summary of Cu/Ni smelter SO_2 control systems is given in Table B.2.6.

For those plants where it is not practical or economical to market sulphuric acid because of remote location or market saturation, the cost of acid neutralization and gypsum impounding must be added. The operating costs for total fixation of the sulphur in smelter gases are shown in Table B.2.7.

Technology for fixing sulphur as elemental sulphur is also available. However, it is much more expensive ($129/tonne sulphur) than producing either sulphuric acid or liquid SO_2. A relatively concentrated SO_2 stream of low oxygen content is required together with substantial quantities of reductant. Therefore it is not applicable to most existing smelter gas streams.

TABLE B.2.7 COST OF SULPHUR FIXATION WITH NEUTRALIZATION AND GYPSUM IMPOUNDING OF H_2SO_4 STREAM (EPS-3 AP-79-8) ($ CAN. June, 1979)

	$/Tonne Sulphur Fixed Double Catalysis	Single Catalysis
All Gases to Sulphuric Acid and Acid Neutralization		
(1) 540 t/day H_2SO_4	169	164
(2) 1 100 t/day H_2SO_4	144	140
Liquid SO_2, Acid Production and Acid Neutralization		
(1) 160 t/day SO_2 and 540 t/day H_2SO_4 to neutralization	158 - 163	155 - 160
Elemental Sulphur, Acid Production, and Acid Neutralization		
(1) 270 t/day elemental sulphur and 540 t/day H_2SO_4 to neutralization	155	152

NOTE: Liquid SO_2 and elemental sulphur are produced from high-grade continuous gas streams. Lower-grade variable converter gases are processed to sulphuric acid, which is neutralized and impounded.

TABLE B.2.6 COPPER/NICKEL SMELTER SO_2 CONTROL SYSTEMS

Smelter Process				SO_2 Control System						
Technology	Cost	Technology Availability	Energy Consumption	Technology	SO_2 Control %	Cost	Availability Technology	Operating Reliability	Energy Consumption	By-Product
Multi-hearth roaster, reverb., converter	Med.	High	High	Non-regenerative FGD	To 85%	High	Low	Low	High	Sulphur compound for waste disposal
Multi-hearth roaster, reverb., converter	Med.	High	High	Regenerative FGD + Acid	To 85%	High	Low	Low	High	Sulphuric acid
Fluid-bed roaster, reverb., converter	Med.	High	High	Acid plant on roaster	To 45%	Low	High	High	Low	Sulphuric acid
Fluid-bed roaster, reverb., converter	Med.	High	High	Acid plant on roaster & non-regenerative FGD on weak gas streams	To 90%	High	Low	Low	High	Sulphuric acid and sulphur compound for waste disposal
Fluid-bed roaster, reverb., converter	Med.	High	High	Acid plant on roaster & regenerative FGD on weak gas streams & acid plant	To 90%	High	Low	Low	High	Sulphuric acid
Fluid-bed roaster, electric furnace, converter	High	High	Very High	Acid plant on roaster, electric furnace, converter	To 90%	Low	High	High	Low-Med.	Sulphuric acid
Fluid-bed roaster, electric furnace, converter	High	High	Very High	Acid plant on roaster, electric furnace, converter plus FGD system on weak gas streams	To 95%	Med.	Med.	Med.	Med.	Sulphuric acid and sulphur compound for waste disposal
Direct furnace smelting, converter (Inco, Outokumpu, Noranda)	Low	High[1]	Low	Acid plant on flash furnace & converter	To 90%	Low	High	High	Low	Sulphuric acid
Direct furnace smelting, converter (Inco, Outokumpu, Noranda)	Low	High	Low	Acid plant on flash furnace plus FGD system on weak gas streams	To 95%	Med.	Med.	Med.	Med.	Sulphuric acid and sulphur compound for waste disposal
Continuous smelting (Mitsubishi, Noranda)	Low+	Med.[2]	Low	Acid plant	To 98%	Low	High	High	Low	Sulphuric acid
Hydrometallurgy	High	Low[3]	High to Very High	?	To 99.5%	?	?	?	?	Elemental sulphur

[1] Unknown

[2] Can be used only for clean copper concentrates.

[3] Problems with precious metals recovery, limited operating experience; could be considered for some special cases

Source: Background document in preparation

The uncertainties in the data base are similar to those discussed in Section B.2.2.1 except that the capital cost uncertainty is estimated at ± 25% and the operating cost uncertainty is estimated at no greater than ± 30%.

By-product disposal problems are basically the same as in those discussed in Section B.2.2.1 since the technologies used are the same. The only exception is that the problems are likely to be more frequent since the presently controlled smelters may have already captured much of the existing sulphuric acid market. If elemental sulphur is produced, the disposal problems are minimal, even if the sulphur has to be stockpiled.

The energy consumption is similar to that discussed in Section 2.2.1 except in the case of elemental sulphur production, which is an energy-intensive process.

B.2.2.3 Emerging Control Technology

As previously mentioned, the most common mode of collecting SO_2 in the smelting industry is to use a sulphuric acid plant. The gases from fluid-bed roasters and converters (sometimes) are high enough in SO_2 concentration for direct processing in a conventional acid plant. This is the lowest-cost approach and recovers a usable by-product. However, the 0.5 to 1.5% SO_2 average concentration in reverberatory furnace off-gas is not sufficiently high for direct processing of the gas in a conventional sulphuric acid plant. For this reason, flue gas desulphurization (FGD) systems have been incorporated at a few smelters under specific conditions. They may be classified as regenerative and non-regenerative; the former produces SO_2 as a more concentrated gas, and the latter generally converts it to a throwaway by-product.

The non-regenerative systems essentially neutralize the SO_2 and place it in a stable form which can be disposed of with minimal adverse effects on the environment. Most regenerative systems absorb the SO_2 and then regenerate it as a more concentrated stream which can then be used to make either liquid SO_2, sulphuric acid, or sulphur. In those cases where the sulphuric acid market is such that additional production is not saleable, the non-regenerative systems would seem to be the logical choice for controlling SO_2 from the smelter reverberatory furnace. In those cases where a usable by-product is desired, then several possible concentration systems have been proven feasible at full-scale operations on reverberatory furnace off-gases. The costs, however, are very high and each retrofit system must be considered on an individual basis. Of the non-regenerative throwaway systems, the one that has received the most use for collecting SO_2 is the lime/limestone gypsum system. Of all the potential regenerative (concentration) systems that have been considered, the metallurgical gas experience has been with the MgO, ammonia and the cold water adsorption systems. The citrate process has operated on a pilot-plant scale.

Each of the FGD scrubbing systems has seen application at only one smelter; the MgO and lime/limestone at the Onahoma smelter in Japan, ammonia at Cominco, Canada, dual alkali at Afton, Canada and cold water at Boliden, Sweden. Flakt and Boliden are jointly developing a citrate system for smelter weak SO_2 which is in the pilot stage. Currently the state-of-the-art is such that FGD by wet scrubbing can be accomplished, but there are significant financial and technical risks in the selection, design and application of such systems owing to lack of extensive pilot experience on various types of concentrates. Because of the nature of the scrubbing processes, energy consumption will generally be substantial and disposal of waste products will often create environmental problems. Work underway will provide background information for these aspects.

The costs (capital and operating) for these systems are being developed and will be available for inclusion at a later date.

B.2.3 ALTERNATIVE PRODUCTION PROCESSES

Processes that Provide Gases More Amenable for SO_2 Control

Many existing smelters have equipment such as multiple-hearth roasters and reverberatory furnaces which produce gases too low in SO_2 for direct processing to sulphuric acid. The multiple-hearth roasters can be replaced by fluid-bed roasters, and thus up to 45% of the sulphur can be produced in an SO_2 concentration high enough for sulphuric acid production. An even greater improvement can be achieved by replacing both multiple-hearth roasters and reverberatory furnaces by flash smelting units which can produce 60% or more of the sulphur as high-strength SO_2 gas.

Conventional converting in most smelters is a batch operation that produces a gas stream of variable SO_2 content which is difficult to process into sulphur by-products. Continuous smelting processes such as the Mitsubishi process and the Noranda process produce a continuous high-strength gas. However,these processes have been proven only for certain "clean" copper concentrates.

Processes That Eliminate SO_2 Formation

Hydrometallurgical processing of nickel sulphide concentrates has been practised by one Canadian company for 20 years and the hydrometallurgical processing of copper and zinc concentrates are in various stages of research and development. While these processes do not produce SO_2 gas, they have not been widely used owing to factors including high costs, problems with recovery of precious metals, high energy consumption and lack of adequate development.

Processes that Reduce Sulphur Input to the Metallurgical Processes

In some cases, it is possible to modify the ore benefication processes to reject a greater amount of sulphide minerals than normal. This is practised, for example, in the nickel industry where part of the pyrrhotite is rejected in the milling and concentration stage thus reducing the sulphur to metal ratio of the concentrate entering the smelter. Some metal values (including nickel, cobalt, platinum, etc.) are lost with the rejected pyrrhotite, and a compromise is made between metal values lost and sulphur rejected.

B.2.4 PRELIMINARY COST OF CONTROLS FOR EASTERN CANADIAN SMELTERS

Preliminary costs have been developed for one level of SO_2 emission control for eastern Canadian non-ferrous smelters. The exact level varies from smelter to smelter depending on the present level of control, concentrate characteristics and production processes. The costs are based on preliminary estimates. Current work underway will provide more accurate costs for control to this level and also will provide cost estimates for more stringent levels of control.

The costs include modifications and/or improvements to existing operations, replacement of some production process unit operations, modifications to flues and flue gas cleaning facilities, sulphuric acid plants, sulphuric acid storage, handling and transportation facilities and sulphuric acid disposal. No control of weak gas streams is included at this time.

The estimated capital cost to reduce SO_2 emissions (at smelter capacity) from 2.7 million tonnes per year to 1.17 million tonnes per year (a 57% reduction) is $1.1 billion. The net increase in annualized costs is estimated at $120 to $150 million. (Note: includes major changes at four smelters and minor changes at two smelters).

The net increase in annualized costs is equivalent to 15¢ to 20¢ per lb of nickel and 5¢ to 8¢ per lb of copper.

A number of factors may change these costs as a result of further work underway. The costs of acid sale/disposal may be low for the remote smelters it may be necessary to neutralize some of the acid produced, etc.

The above costs include those identified in the preliminary feasibility study which was carried out for the Inco copper-nickel smelter at Sudbury, Ont. The estimated cost at capacity operations for a reduction of SO_2 emissions from 1.14 million tonnes per year to 0.41 million tonnes per year (64%) was $480 million. This reduction was based on the installation of sulphuric acid plants and major process changes. The estimated net increase in annualized costs was $60 to $65 million (includes capital and operating costs).

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B.3 MOBILE SOURCES

B.3.1 Description of Sector

In the transportation sector gasoline and diesel-powered road vehicles account for about 70% of NO_x emissions while a further 20% comes from non-highway applications of gasoline and diesel engines. Thus, with federal design emission standards in both countries for such vehicles (and/or engines), over 90% of the NO_x emission inventory is already subject to controls of varying stringency at the new vehicle/engine level.

Emissions of SO_x from mobile sources are negligible (about 1.5% of man-made emissions).

B.3.2 CONTROL TECHNOLOGIES

B.3.2.1 United States - New Vehicles

In the United States, tailpipe emission standards are in effect for a variety of light- and heavy-duty vehicles, including motorcycles and airplanes.

In examining emissions of any pollutant from road vehicles one can divide the subject neatly into two parts: the design performance of vehicles, usually covered under new vehicle/engine emission regulations, and the actual emissions performance of vehicles in consumers' hands, including both the amount and kind of use each vehicle sees.

B.3.2.1.1 Light-Duty Vehicles

Current emission standards are in effect for light-duty vehicles (LDV's) which require a 90% reduction in hydrocarbons (HC) and carbon monoxide (CO), and a 75% reduction in nitrogen oxides (NO_x) as compared to 1970 model passenger cars.

There have been a series of emission control devices on passenger cars since the 1960's; however, beginning with the 1972 production models, emission control devices began to bring about significant reductions in air pollutants. In 1975, the catalytic converter was introduced on a large scale and has since become the primary system for controlling HC and CO. The technology for meeting the current automobile emission standards employs the catalyst technology coupled with a series of electronic and vacuum sensing devices which detect and control selected engine operating parameters. A so-called three-way catalyst (incorporating NO_x reduction as well) is being used on many of the 1980 production cars.

All the federal emission standards apply only to new production cars. Because the standards themselves have changed over time, and because it takes 8 to 10 years for an effective turnover of the vehicle fleet, it will still be a number of years before the total potential of the federal emission standards for LDV's can be fully realized.

Table B.3.1 provides a breakdown of the cost of the individual components of a typical three-way catalyst. As can be seen, the system (which controls all three pollutants) is estimated to cost about $300 per car. The catalyst is expected to continue to be the primary emission control technology for the foreseeable future.

TABLE B.3.1 COST OF COMPONENTS IN A THREE-WAY PLUS OXIDATION CATALYST SYSTEM

Component	Cost (1979$) Minimum	Maximum
Throttle position sensor	$ -	$ 2.2
PCV valve	1.1	1.1
HEI (less breaker point distributor)	7.7	7.7
TVS (spark)	-	2.2
Electric choke	1.1	1.1
EFE	4.4	4.4
EGR (backpressure)	7.7	7.7
TVS (EGR)	-	2.2
Stainless steel exhaust pipe (less steel pipe)	9.9	9.9
Air injection system	33.0	33.0
Air switching system	2.2	2.2
Feedback carburetor (less open loop carburetor)	8.8	8.8
Three-way plus oxidation catalyst	172.7	172.7
ECU	33.0	33.0
O_2 sensor	3.3	3.3
H_2O temperature sensor	-	2.2
Inlet air temperature sensor	-	2.2
Engine speed sensor	-	2.2
Crank angle position sensor	-	2.2
EGR pintle position sensor	-	2.2
Evaporative system	11.0	11.0
TOTAL	$295.9	$313.5

Source: Lingren, LeRoy H. (Rath and Strong, Inc.). March 1978. "Cost Estimation for Emission Control Related Components/Systems and Cost Methodology Description." EPA-460/3-78-002.

B.3.2.1.2 Light-Duty Trucks

Because light-duty trucks (LDT's) perform different functions than passenger cars, it is difficult to achieve the same level of emission reduction even though the same engines are interchangeably used in many cases. Consequently, the U.S. emission standards for LTD's are somewhat less stringent than corresponding standards for passenger cars. For comparison, emission standards (in grams/mile) for model year 1981 LDT's and LDV's are listed below:

	HC	CO	NO_x
LDV's (1981)	0.4	3.4	1.0
LDT's (1981)	1.7	18.0	2.3
LDT's (1983)	0.8	10.0	2.3 (possibly 1.2)

Generally, the same basic technology is used for both LDT's and LDV's. However, some of the electronic sensors or such add-on systems as the air pump may not be required. The cost of the control system will be very similar to that previously presented for LDV's.

B.3.2.1.3 Heavy-Duty Trucks

Heavy-duty trucks are usually divided into two categories, gasoline-powered and diesel-powered. Control technology for both categories is available. The Clean Air Act Amendments of 1970 require that standards be established in the U.S. which will provide a 90%, 90%, and 75% reduction in HC, CO, and NO_x as compared to that produced in 1973. For HC and CO, the technology is available to achieve these reductions; however, the availability of technology for achieving the required reduction in NO_x, particularly for the diesel engine, is questionable.

B.3.2.1.4 Cost of U.S. FMVCP

Table B.3.2 provides a summary of the estimated annualized cost of the FMVCP in 1987. The table includes cost savings as the result of reductions in fuel and maintenance which resulted from the installation of more sophisticated engine controls to meet the stringent emission standards mandated by the FMVCP.

TABLE B.3.2 TOTAL ANNUAL COST OF THE FMVCP IN 1987 (1979$ X 10^6)

Type of Vehicle	Annual Cost of Control
Passenger Cars (LDV's)	
Hardware	$6006
Fuel economy	(5130)[a]
Unleaded gasoline cost	2199
Operating and maintenance	(1917)
Altitude controls	834
Sub-total	1992
Light-Duty Trucks (LDT's)	
Hardware	2220
Fuel economy	0
Unleaded gasoline cost	1062
Operating and maintenance	0
Altitude controls	300
Sub-total	3582
Heavy-Duty Trucks (HDV's)	
All costs	862
Motorcycles	
All costs	92
Aircraft	
All costs	92
TOTAL COST	$6620

[a] Negative costs

B.3.2.2 United States - In-Use Vehicles

B.3.2.2.1 Inspection and Maintenance

Although the FMVCP has achieved significant emission reductions, the overall performance of the program has been somewhat less than desired. This is because the control systems have historically exhibited a high rate of deterioration, primarily due to owner or mechanic tampering in an attempt to improve driveability. There have also been indications that the use of leaded gasoline in about 10% of automobiles equipped with catalytic converters has reduced the overall effectiveness of the FMVCP since lead destroys the capability of the catalyst to perform its function.

To ensure that the control systems continue to function as designed, a number of major urban areas have adopted or plan to adopt a system of frequently inspecting automobiles, and requiring proper maintenance on those vehicles that fail to meet the emission standards. Such programs automatically incorporate an allowance for deterioration which is dependent upon vehicle age and is taken into account during the inspection. This system is frequently referred to as Inspection and Maintenance (I&M) and is required by the Clean Air Act Amendments of 1977 to be implemented in all areas that cannot meet the national ambient air quality standards by 1982.

The effectiveness of an I&M program is dependent upon many factors, including the degree of stringency, the frequency of inspections, the training of inspectors, etc. However, an effective I&M program can provide between 10% and 25% more emission reduction for HC and CO than possible through the FMVCP only. Reductions for NO_x through I&M are somewhat lower but generally an estimated 5% to 10% improvement is possible.

Inspection costs run between $5 and $10 per car and the repair cost have averaged just under $30 for each car that failed the inspection. Generally, systems in operation at the current time have been designed around a 30% failure rate. The annualized cost of an I&M program to meet current U.S. air quality standards by 1987 is estimated to be around $400 million. Potential fuel savings as a result of maintaining proper tuning of the cars may reduce this cost to approximately $250 million.

B.3.2.2.2 Transportation Control Measures

If emission reductions beyond those achievable with tailpipe standards are required, transportation measures can be used. These measures involve a host of possible alternatives ranging from simple cost-saving programs such as carpooling to extensive major rerouting of traffic, gasoline rationing or mass transit systems. Because of the variety of options, it is difficult to estimate the cost of such programs. However, there are indications that the simple and inexpensive options do offer some emission reduction potential (maybe 5%). Generally, these less expensive options also offer some form of fuel savings.

B.3.2.3 Canada - New Vehicles

In Canada new light-duty vehicles are currently subject to an emission standard for NO_x of 3.1 grams per mile (gpm). Many of the vehicles, however, meet the U.S. standard of 2 gpm for the late '70's models and, from 1981 on, 1 gpm. Thus the weighted average design emission level would be about 5 gpm until 1973, 2.8 gpm to 1980 and 2.3 gpm thereafter. The current 3.1 gpm standard is under review and the decision on the emission standard for 1985 and later models is expected within 18 months.

B.3.2.4 Canada - In-Use Vehicles

The actual NO_x emissions from vehicles in consumers' hands are affected by a large variety of factors including ambient temperature, individual driving style, state-of-tune of the vehicle, mode of operation, and, recently discovered to be of major importance, direct tampering with NO_x emission controls.

Investigations into tampering with EGR valves have indicated that the tampering rate may well be as high as 30% rather than the 5 to 10% previously estimated. Thus, we are no longer satisfied that our emissions model is accurate. With that caveat our current estimate is that the average (whole fleet) emissions were in the neighborhood of 4.5 gpm until 1975, about 3.5 from then until 1980 and, in the absence of further investigation/control on the tampering rate, about 3 gpm thereafter.

A national guideline (I/M) for the control of excess emissions and fuel consumption by in-use vehicles will soon be promulgated. It advocates a "phase-in" approach, starting with new vehicles and using very stringent standards that would be equivalent to a 75% failure rate on the U.S. program discussed in B.3.2.2.1. As a result a mature program is expected to reduce CO emissions by 40 to 50%, HC emissions by 20% and fuel consumption by 3 to 5% on the subject fleet. The dollar value of the gasoline savings will exceed the total societal cost of the program.

B.4 PETROLEUM REFINING

B.4.1 Canadian Petroleum Refineries

Location: There are 33 operating refineries located across Canada, with 4 in the Maritimes, 7 in Quebec, 8 in Ontario, 1 in the Northwest Territories and 13 in Western Canada.

B.4.1.1 Production Processes

Refineries differ in their processing layout, depending on their capacity, type of crude oil processed, complexity of the processes involved, product specifications, and product requirements. Generally, the following processes are used in petroleum refining after washing crude oil with water for salt removal (desalting).

B.4.1.2 Separation

(a) Atmospheric distillation, to separate light and/or heavy oil fractions
(b) Vacuum distillation,to separate heavy oil fraction into gas-oil, lube-oil, and residue

B.4.1.3 Conversion

(a) Catalytic cracking
(b) Catalytic naptha reforming
(c) Light hydrocarbon processing
    (i) polymerization
    (ii) alkylation
(d) Isomerization
(e) Coking
    (i) Delayed
    (ii) Fluid-bed
(g) Desulphurization of fuel oils
(h) Sulphur recovery by Claus Process

B.4.1.4 Treating: removal of H_2S and mercaptans from light hydrocarbons by amine and chemical treatment (sodium plumbite or copper chloride).

B.4.1.5 Blending: Blending of base stock to meet the applicable specifications.

B.4.1.6 Emissions: Annual emissions for this industry sector are 263 000 tonnes/year $S0_2$ (92 000 from refining processes; 171 000 from combustion processes) and 45 800 tonnes/year NO_x (4 400 from refining processes, 41 400 from combustion processes). These emissions result from refinery process heaters and boilers, sulphur recovery plants, fluid catalytic cracking units, incinerators and flares.

Available technologies could be installed to substantially reduce SO_2 emissions from fluid catalytic cracking (FCC) regenerators and sulphur plants on existing plants. Emissions could also be reduced significantly if the refineries switched to low-sulphur fuels in the refinery fuel system.

This industry sector is not presently being rigorously addressed. However, as strategy options are developed, several major metropolitan areas that contain refineries could be involved, necessitating a further assessment of this sector.

B.4.2 United States Petroleum Refineries

In terms of total mass emissions of SO_x and NO_x, petroleum refineries contribute a relatively small percentage of the total U.S. emissions of these pollutants. Specifically, refineries contribute 3.9% of the SO_x emissions and 0.85% of the NO_x emissions. Geographically, a majority of the U.S. refinery capacity is in the Gulf Coast and West Coast areas of the United States, but a significant portion is in the north central (2.4×10^6 BPD, 14%) and northeastern (1.8×10^6 BPD, 10%) parts of the country. Existing fuel gas and sulfur plant regulations, anticipated regulations for sulfur oxides from FCC units and anticipated regulations for industrial boilers indicate that any increased refinery capacity will have the minimum emissions of SO_x and NO_x.

No detailed assessment has been published on the contributions of SO_x and NO_x emissions resulting from refinery fuels used in process heaters and boilers.

No grass-roots refinery capacity is expected to be added in the near future. However, an indeterminate amount of refinery upgrading which includes FCC capacity is expected to be added over the next few years. This upgrading may increase or decrease SO_x and NO_x emissions depending on the extent to which new controlled processes replace old uncontrolled ones. There is no study available at this time that predicts what refinery emissions will be as a result of the anticipated upgrading.

B.5 INDUSTRIAL, RESIDENTIAL, COMMERCIAL FUEL COMBUSTION

Sulphur and nitrogen oxide emissions from non-utility fuel combustion in Canada are about 1.1 million tons and 600 000 tons per year respectively. For the United States, these sources account for some 7.3 million tons of SO_2 emissions and 7.1 million tons of NO_x emissions.These numbers include those emissions already identified in the fuel combustion portion of the larger industrial sectors. The vast majority of these emissions are associated with heavy and light oil combustion and as a result are mainly confined to the larger urban and industrial areas.

Control technology in this sector is size specific, with flue gas desulphurization and low-NO_x combustion modifications applicable to the larger-sized combustion units of the industrial sector. Control technology in the commercial and residential sector has not progressed as rapidly as with the larger boilers, primarily because of the smaller emission reduction potential. However, it is known that some emission reduction is economically possible in the commercial and residential sectors.

Oil desulphurization to reduce SO_2 emissions is a well-developed technology although no facilities exist in Canada. Residual (heavy) oil can be readily desulphurized to 0.5%S and light oils to 0.3%S. The cost varies with the type of crude oil and increases with the degree of desulphurization.

The main role for desulphurized oil with respect to the acid deposition problem would be to reduce area emissions from large urban areas.

B.5.1 Industrial Combustion Units

As in the utility boiler sector, a variety of control strategies can be used to reduce sulphur oxide emissions. These strategies include low-sulphur fuel, wet or dry flue gas desulphurization and fluid-bed combustion. Low-sulphur coal and hydro desulphurization of fuel oil can be used to reduce SO_x emissions to about 1.2 lb/10^6 Btu and 0.2 lb/10^6 Btu, respectively. Although flue gas desulphurization can lower potential sulphur oxide emissions by up to 90%, there are no units in operation at present in Canada. Fluid-bed combustion can achieve a 70-85% SO_2 reduction and about a 70% reduction in NO_x at operating costs competitive with flue gas desulphurization. The capital cost of the fluid-bed boiler will exceed that of a conventional coal combustion system.

Combustion modification is the principal method of controlling NO_x emissions. The NO_x emission limits achievable using combustion modification are dependent upon the fuel type (oil, coal, gas) and firing method. Studies are presently being done to delineate the optimum methods available.

The cost of retrofitting industrial boilers is highly uncertain since space limitations and other restrictions can cause significant variations.

B.5.2 NO$_x$ and SO$_2$ Control Technologies Available

The dual-alkali wet flue desulphurization process is the dominant sulphur oxide control technology for industrial boilers. Sodium once-through systems are used in industries which produce a sodium-containing waste stream such as pulp and paper and textile mills (from de-ionizer recharging). There are two commercial installations of the lime spray dryer SO$_2$ control process. The cost of SO$_2$ control technology varies as a function of boiler size, load factor, and fuel sulphur content. Thus the uncertainty in capital and annual costs can be large. The capital costs and operating costs shown in Figures B.5.1 and B.5.2 can be in error by as much as ±40 percent.

Frequent operating or other scheduled shutdowns in some industries could create problems in the operating reliability of some control processes. The disposal of scrubber sludge also presents a problem.

Field trials are underway on retrofitting a coal-fuel unit to the low-NO$_x$ firing mode through burner modifications. Although these are being performed in a utility unit, the technology is expected to be available to the larger-sized industrial coal-fired units. Feasibility studies and modification scheduling are being conducted for the retrofitting of an industrial coal-fired unit to Limestone Injection/Multi-stage Burners for the simultaneous reduction of SO$_2$ and NO$_x$. This field trial is being performed on a military base in New Brunswick and is expected to demonstrate this technology further, for use in the large industrial and utility boiler sector.

The construction of a fluidized bed combustion unit is scheduled for early spring 1981. The operation of this unit will provide data on reliability, costs and performance of simultaneous sulphur and nitrogen oxide control from high-ash, high-sulphur coals in addition to other coals presently available in eastern Canada.

B.5.3 Residential and Commercial Combustion Units

Control technology in these sectors has not progressed as rapidly as for the larger boilers, primarily because of the considerably smaller emission reduction potential for this sector. However, research has estimated that some emission reduction is economically possible for commercial and residential boilers.

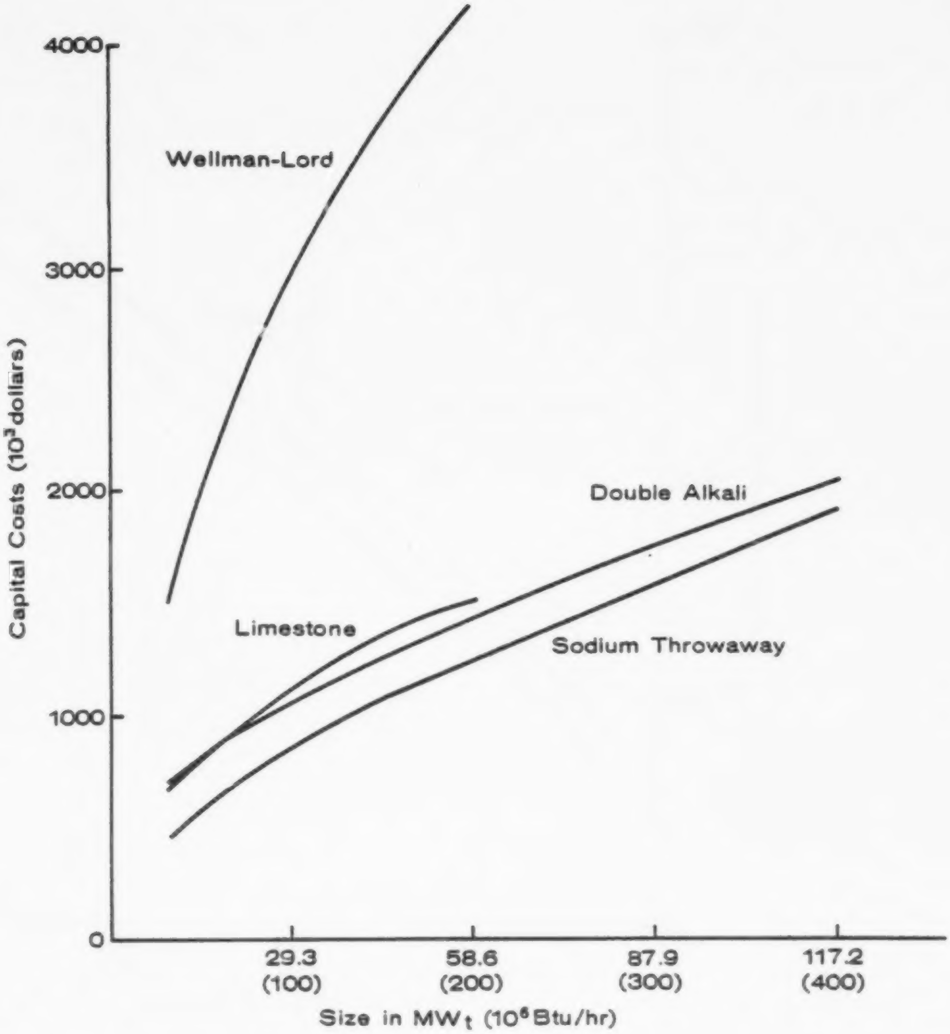

FIGURE B.5.1. FGD CAPITAL COSTS VERSUS UNIT SIZE
(3.5% S coal, 90% removal)

Source: Technical Assessment Report for Industrial Boiler Applications:
Flue Gas Desulfurization
Industrial Environmental Laboratory; U.S. E.P.A., November 1979

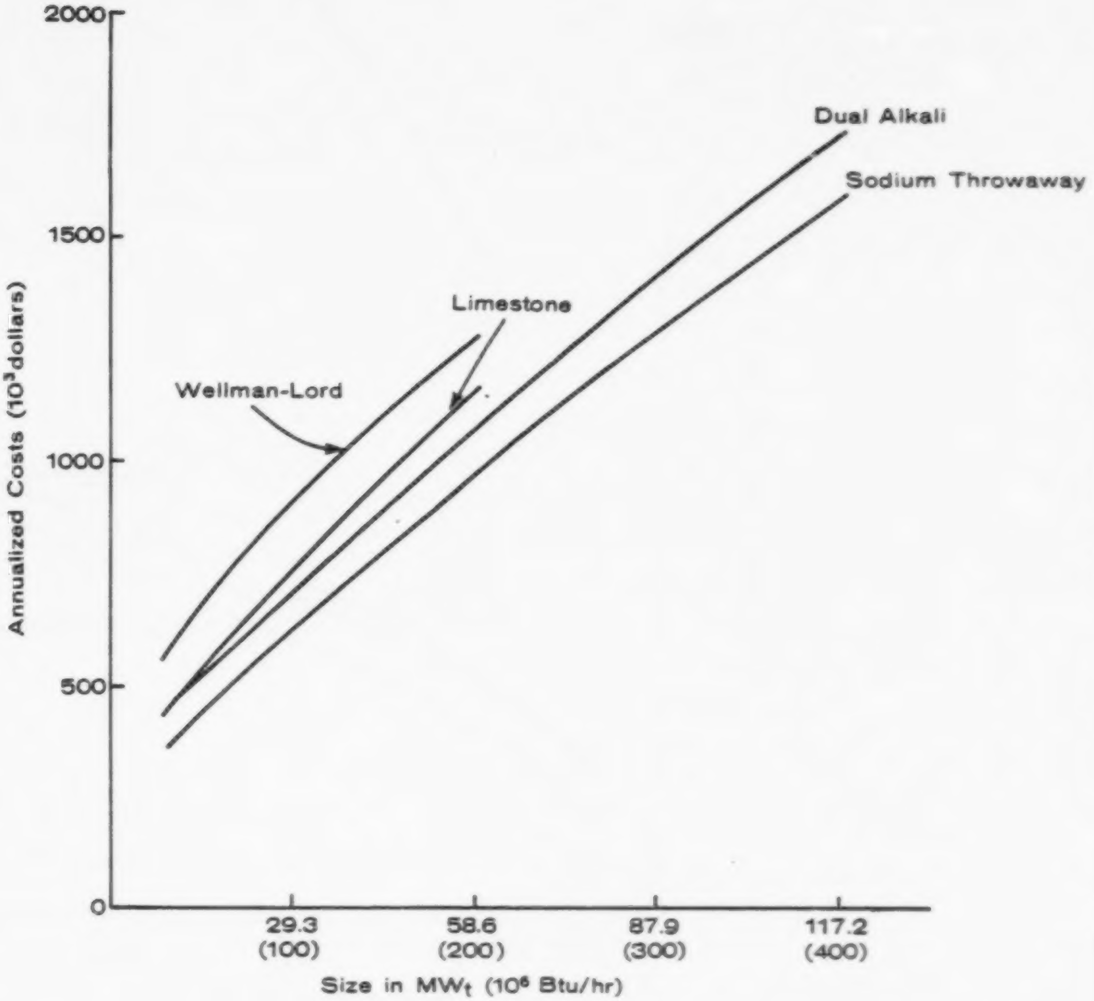

FIGURE B.5.2. FGD ANNUALIZED COSTS VERSUS UNIT SIZE
(3.5% S coal, 90% removal)

Source: Technical Assessment Report for Industrial Boiler Applications:
Flue Gas Desulfurization
Industrial Environmental Laboratory; U.S. E.P.A., November 1979

Research by the U.S. Environmental Protection Agency has shown that proper maintenance and operation of existing commercial and residential heating units are the most economical means of reducing emissions from these sources. Such practices also provide fuel savings which can potentially offset maintenance cost. Education of owners and operators is the best means of achieving the desired maintenance and operating practices.

In a recent study of home heating units, it was found that by identifying and replacing untuneable units and by tuning the remaining units, smoke could be reduced by 50%, CO by 81%, HC by 90% and filterable particulate by 24%. A recent EPA study indicates that by proper design of residential heating systems, it is possible to achieve a 65% reduction in NO_x emissions, and at the same time, to reach a steady state thermal efficiency of 70 to 80%. The fuel reduction potential was found to approximate 20 percent. The prototype version of the system has been field-tested, and the above results are from this test.

Cost figures for this system are not available, but indications are that any increase in cost will be greatly offset by the fuel savings and increased thermal efficiency.

B.6 INCINERATORS

Canada

Municipal incinerators emit significant amounts of particulate matter, and lesser amounts of sulphur dioxide and nitrogen oxides to the atmosphere. A large municipal incinerator (1000 tonnes per day), for example, emits 550 tonnes per year (tpy) of particulates, 300 tpy of sulphur dioxide, and 350 tpy of nitrogen oxides (1). Emissions per tonne of material incinerated tend to be equivalent or less than other types of controlled incineration such as controlled air incinerators or sewage sludge incinerators.

Control techniques for particulate emissions from incinerators are fairly advanced; however, little, if anything, has been done to reduce sulphur dioxide or nitrogen oxide emissions. Given the relatively low concentration of sulphur in municipal refuse and the low operating temperature of municipal incinerators and consequently low NO_x production compared to fossil-fuel combustion, it would be impractical to achieve significant reduction in these emissions. The EPA control techniques document for nitrogen oxides suggests alternative disposal methods (e.g., landfill) as the only practical control technique for nitrogen oxides from incineration.

Emissions of SO_2 and NO_x from incineration in Canada are 3 245 tpy and 5 094 tpy respectively. Large incinerators are located in Quebec City, Montreal, Toronto and Hamilton. The emissions of SO_2 and NO_x are a small part of overall Canadian emissions, and incineration is not considered to be of significance in the acid rain problem.

There are no hazardous waste incinerators operating in Canada.

U.S. Solid and Hazardous Waste

As a generalization, much of the municipal solid waste incineration is centered in the Great Lakes and New England areas while hazardous waste incineration is limited by comparison but is likely to be more ubiquitous.

Estimated emissions of NO_x from solid waste disposal in the U.S. indicate a decrease from about 0.6 million tpy in 1968 (AP-84), to 0.3 million tpy in 1970, to a current level of about 0.1 million tpy (draft criteria document for NO_x, 6/79) because of a reduction in the amount of waste burned. Air pollution control systems currently applied to such incinerators or those likely to be required in the future do not generally remove appreciable amounts of SO_x and NO_x.

REFERENCES

1. EPA Publication AP-42, "Compilation of Air Pollutant Emission Factors", third edition, August 1977.

B.7 PULP AND PAPER INDUSTRY

B.7.1 United States Pulp and Paper Industry

It is estimated that total SO_x and NO_x emissions from process operations are approximately 157 000 and 45 000 tonnes per year respectively from about 400 mills. The combustion of fossil fuels for the production of additional steam and power in this industry sector contributes an additional 720 000 and 180 000 tonnes per year of SO_x and NO_x respectively. There are no other significant acid rain precursor emissions or direct acidic emissions from this industry sector. Since this industry is not expected to undergo major expansions during the balance of this century, its relatively minor contribution to the total transboundary air pollution problem is unlikely to be altered.

As regards the geographical distribution of pulp and paper facilities, about one third are located in the northeastern region, about one quarter are in the Pacific northwest, and the balance are widely dispersed. The low gross emissions of SO_x, together with the wide geographic distribution of the mills and the expectation that no significant expansion of this industry will occur, indicate that transboundary transport of acid rain precursor emissions from the pulp and paper industry is of secondary importance.

B.7.2 Canadian Pulp and Paper Industry

It is estimated that total SO_x and NO_x emissions from process operations are approximately 88 000 and 13 000 tonnes per year respectively from 114 mills. The combustion of fossil fuels for the production of additional steam and power in this industry sector contributes an additional 144 000 and 45 000 tonnes per year of SO_x and NO_x respectively. These emissions are split roughly 80/20 between eastern Canada and British Columbia. It is anticipated that a current federal-provincial modernization program will reduce existing emissions. Similiar to the U.S., no significant expansion of production capacity is anticipated in the near term. These factors indicate, as in the U.S., that transboundary transport of acid rain precursor emissions from the pulp and paper industry is of secondary importance.

C HISTORICAL EMISSION TRENDS

C.1 INTRODUCTION

The primary objective in developing historical emission trends is to recreate the emission situation of several decades ago so that such data can be used in atmospheric models to provide an insight into sulphur deposition rates for those periods. These rates can then be compared to current deposition rates for an indication of the rate of degradation of the environment with time.

Factors other than strict fluctuations in the magnitude of acid precipitation precursor emissions, however, have also played a role in changes in deposition rates with time and these should not be overlooked. For example, concurrent with increases in SO_2 and NO_x emissions over the past 40 years has been a substantial increase (by a factor of five) in the stack height for utility sources. Also, SO_2 emissions from coal burning have changed in most regions from a wintertime peak to a summertime peak in emission rate. The importance of such factors has not been well determined at this time.

C.2 IN THE UNITED STATES

Methodology: Emission calculations for the United States have been made on a broad national scale as well as on a much more refined scale. Similar methodologies have been employed in making these calculations.

Historically, data records on emissions and emission rates have been maintained only since the early 1970's. Consequently, in order to recreate such emissions, it is necessary to use other information. One of the most accepted approaches to retrospectively calculating emissions is to employ fuel use data. Records on these data are available and provide an indication of how various type fuels have been consumed by different type sources. Knowing the emission rates of various sources, the sulfur content of the fuel, and the type of emission controls on a particular type source, it is possible to estimate the emissions of various source categories.

Data Uncertainty: It is extremely difficult to provide an accurate estimate of the data uncertainty in making the above calculations. Generally, the fuel use data on a national scale are quite accurate. However, as one attempts to extrapolate fuel use to a particular type, some errors of uncertain magnitude enter. Moreover, records on the chemical analysis of the fuel were not maintained until the 1960s and therefore one must make assumptions for such important factors as sulfur content of the fuel used.

Generally, it is felt that the emission estimates for the utility sector are probably within 25% accuracy for the post-1965 years; however, no accuracy figures are available for the pre-1965 estimates.

No attempt has been made to assess the accuracy of the calculations for other sources, except to examine the general trends exhibited to determine areas where the trends are well outside of what might be expected.

National Trends in Emissions: Table C.2.1 provides a summary of the emissions of various air pollutants in the United States between the years 1940 and 1976. The data in the table are the estimated total emissions throughout the United States for the year of record indicated. Additional information on the total national emissions from various sources along with an expanded discussion of the procedures for calculating these emissions can be found in the publication "National Air Pollutant Emission Estimates 1940-1976", EPA-450/1-78-003, July 1978, available through the Office of Air Quality Planning and Standards, U.S. EPA, Research Triangle Park, N.C. 27711. Table C.2.2 provides an indication of the information contained in the above references.

TABLE C.2.1 SUMMARY OF NATIONWIDE TOTAL EMISSION ESTIMATES

Units of measurement	Year	SO_x	TSP	CO	HC	NO_x
10^6 tons per year	1940	21.9	27.5	86.7	19.0	6.7
	1950	24.5	29.1	96.6	23.5	9.0
	1960	24.1	28.3	111.0	31.2	11.5
	1970	32.1	24.8	109.9	32.9	22.3
	1971	30.8	23.4	110.2	32.1	23.3
	1972	31.7	22.3	112.3	32.8	24.3
	1973	32.7	21.8	108.2	32.7	25.1
	1974	30.9	19.2	100.7	31.6	24.7
	1975	28.5	16.0	95.3	29.1	24.4
	1976	29.9	14.9	96.6	30.9	25.4
10^6 tonnes per year	1940	19.5	24.8	78.3	17.0	6.0
	1950	22.0	26.2	87.0	21.2	8.1
	1960	21.4	25.6	100.0	28.0	10.5
	1970	29.1	22.6	99.8	29.7	20.4
	1971	27.9	21.4	100.2	29.3	21.3
	1972	28.8	20.3	102.0	29.7	22.2
	1973	29.7	19.9	98.3	29.8	22.9
	1974	28.2	17.5	91.5	28.6	22.6
	1975	25.7	14.4	85.9	26.2	22.2
	1976	26.9	13.4	87.2	27.9	23.0

TABLE C.2.2 ESTIMATED NATIONWIDE EMISSIONS, 1940[a]

Units of measurement	Source	SO_x	TSP	CO	HC	NO_x
10^6 tons per year	Transportation	0.7	0.5	29.0	6.0	1.8
	Highway vehicles	0.0	0.2	26.3	5.4	1.5
	Non-highway vehicles	0.7	0.3	2.7	0.6	0.3
	Stationary fuel combustion	16.8	9.6	3.7	0.8	3.5
	Electric utilities	2.9	2.0	0.0	0.0	0.6
	Industrial	9.3	6.2	0.3	0.3	1.9
	Residential, commercial, institutional	4.6	1.4	3.4	0.5	1.0
	Industrial processes	3.9	11.0	7.2	3.5	0.1
	Chemicals	0.1	0.4	4.4	1.5	0.0
	Petroleum refining	0.2	0.0	0.2	0.5	0.1
	Metals	3.2	3.7	2.3	0.1	0.0
	Mineral products	0.2	4.4	0.0	0.0	0.0
	Oil and gas production and marketing	0.0	0.0	0.0	1.2	0.0
	Industrial organic solvent use	0.0	0.0	0.0	0.1	0.0
	Other processes	0.0	2.5	0.3	0.1	0.0
	Solid waste	0.0	0.6	4.3	0.9	0.1
	Miscellaneous	0.5	5.8	42.5	7.8	1.2
	Forest wildfires and managed burning	0.0	3.8	32.1	5.5	0.9
	Agricultural burning	0.0	1.6	9.1	1.9	0.2
	Coal refuse burning	0.5	0.4	1.2	0.2	0.1
	Structural fires	0.0	0.0	0.1	0.0	0.0
	Miscellaneous organic solvent use	0.0	0.0	0.0	0.2	0.0
	Total	21.9	27.5	86.7	19.0	6.7

[a] A value of zero indicates emissions of less than 50 000 tons per year.

Historical Emission Trends on Regional Scale. To examine emission trends on a regional basis in the United States, a data file has been constructed which also uses historical fuel use figures to calculate emissions of SO_2 and NO_x from various categories of sources. The basic file contains emissions at the individual state level for the following source categories:

Electric Utilities
Industrial
Commercial/Residential
Pipelines
Highway Vehicles
  Gasoline-Powered
  Diesel-Powered
Miscellaneous
Railroads
Vessels
Misc. Off-Highway Mobile
Chemicals
Primary Metals
Mineral Products
Petroleum Refineries
Others

The file currently contains data for 33 eastern states plus the District of Columbia. Years on record for the file are 1950, 1960, 1965, 1970, 1975, and 1978.

For the electric utility sector, all power plants greater than 25 megawatts have been identified and located by the appropriate county within each state for each year of record. Emissions of SO_2 and NO_x have been determined for each year for all such power plants. Consequently, it is possible to identify power plant emissions on a county-by-county level for each year of record for all 33 states. The file identifies each power plant by name, size, county location, and SO_2 and NO_x emissions from coal, oil, and natural gas consumption. The file also contains fuel use information and has some limited data on stack height.

To distribute the non-power plant emissions to a county level, work is underway using historical census data to assign the statewide emissions to the county level. The technique to be used is to apportion the emissions to the county base on a historical population basis. The Brookhaven National Laboratory is currently conducting this work.

As an example of the information from this file, a sample state and county are outlined below in Table C.2.3:

TABLE C.2.3 SO_X EMISSIONS (x 10^3 tons)

State of Kentucky	1950	1955	1960	1965	1970	1975	1978
Non-PP	34.5	153.6	262.3	310.7	198.4	117.7	108.8
Power Plant	28.6	251.2	368.8	603.3	1082.5	1349.1	1221.2
Total	63.1	404.8	631.1	914.0	1280.9	1466.8	1330.0

County of Jefferson, Ky

Power Plant	1950	1955	1960	1965	1970	1975	1978
Canal	1.9	1.5	-	-	-	-	-
Cane Run	-	3.0	11.4	17.0	27.1	22.4	19.1
Mill Creek	-	-	-	-	-	17.8	21.0
Paddy's Run	7.4	10.4	9.4	4.1	3.5	0.7	2.3
Waterside	0.9	0.8	-	-	-	-	-
Total PP	10.2	15.7	20.8	21.1	30.6	40.9	42.4

Non-Power Plant - Jefferson County, Ky
Information not on - file

To assist in examining the historical emission trends on a regional scale, tables have been prepared in which the states are grouped according to the appropriate EPA regional offices (Regions I through V). Trends in SO_x and NO_x emissions for each state along with a summary for each grouping of the states (by regional office) are shown in the following tables (Tables C.2.4 and C.2.5). . To some extent, the regional office grouping can be used to examine trends in the following broad geographical areas of the country:

Regions I and II - Northeast
Region III - Mid-Atlantic
Region IV - Southeast
Region V - Midwest

In the northeast, SO_x emissions appear to have decreased by about 40% from 1955 to 1978. While the trend may be real, it should be noted that the data for 1950 and 1955 are less reliable than for the more recent years. Part of this

TABLE C.2.4 HISTORICAL TRENDS IN SO_2 EMISSIONS

			x 10^3 tons				
State	1950	1955	1960	1965	1970	1975	1978
			EPA - REGION I				
Conn.	130.3	139.1	241.6	457.6	317.3	191.0	112
Maine	37.8	45.6	70.2	97.0	82.0	67.8	66
Mass.	906.4	956.7	374.6	443.2	584.4	362.2	402.2
New Hamp.	73.3	89.7	29.1	41.2	95.9	75.4	67.8
Rhode Island	67.7	80.2	87.3	41.2	60.1	24.3	19.7
TOTAL	1215.[illegible]	1311.3	802.8	1080.2	1139.1	720.7	667.7
			EPA - REGION II				
New York	847.0	1126.0	1427.4	1645.4	1455.0	1079.0	1041.1
New Jersey	*1308.8	*1486.2	482.6	623.4	590.2	341.0	323.7
TOTAL	*2155.8	*2612.20	1910.00	2268.8	2045.2	1420.0	1364.8
			EPA - REGION III				
Delaware	105.4	136.0	196.1	217.8	223.4	193.6	188.2
D.C.	32.4	31.0	38.5	47.9	78.0	27.1	17.6
Maryland	398.9	515.5	518.2	588.1	467.7	322.3	357.3
Penn.	* 970.2	2138.4	2362.2	2546.8	2245.7	2130.8	1900.0
Virginia	157.2	277.4	171.4	188.1	475.2	381.0	359.9
West Va.	243.5	617.8	529.7	776.8	979.7	1220.0	1049.5
TOTAL	*1907.6	3716.1	3816.1	4365.5	4469.7	4274.8	3872.5
			EPA - REGION IV				
Alabama	139.5	522.7	613.5	892.3	979.1	986.5	762.1
Florida	225.5	350.5	341.1	501.6	862.3	827.9	685.9
Georgia	119.9	163.6	198.2	303.0	410.4	571.4	707.0
Mississippi	46.9	43.3	41.1	44.6	79.4	193.0	264.3
Kentucky	113.1	404.8	631.1	914.0	1280.9	1466.8	1330.0
North Carolina	306.1	347.4	232.4	294.4	533.2	500.5	562.3
South Carolina	44.5	84.3	115.9	121.7	185.4	202.3	288.6
Tennessee	97.3	369.2	731.2	771.5	988.1	1141.9	1162.8
TOTAL	1092.8	2285.8	2904.5	3843.1	5318.8	5890.3	5763.0

TABLE C.2.4 HISTORICAL TRENDS IN SO_2 EMISSIONS (Cont'd.)

			x 10^3 tons				
State	1950	1955	1960	1965	1970	1975	1978
			EPA - REGION V				
Illinois	* 869.8	2172.1	2452.9	2791.4	2506.5	1950.6	1747.2
Indiana	533.1	1174.2	1840.8	2180.3	1941.5	1980.0	1848.2
Mich.	519.2	702.7	1085.5	1521.7	1520.9	1450.6	1117.8
Minn.	504.5	536.4	391.8	419.8	450.7	382.3	379.0
Ohio	* 885.0	2344.9	2933.2	3181.2	3125.2	3271.2	3115.3
Wisc.	217.2	304.2	604.0	703.8	322.3	166.6	663.6
TOTAL	*3528.8	7234.5	9308.2	10798.2	9867.1	9201.3	8871.1
			OTHER STATES				
Arkansas	41.0	36.7	26.1	29.9	37.0	68.6	121.6
Iowa	173.2	258.0	364.5	440.8	370.2	314.0	385.0
Louisiana	233.0	261.2	219.4	268.7	318.0	295.1	359.0
Missouri	715.7	*2155.1	582.6	674.9	1107.3	1174.3	1307.7
Texas	1011.7	1073.8	900.0	1074.3	1136.8	1123.8	1244.8

*Questionable data

TABLE C.2.5 HISTORICAL TRENDS IN NO_x EMISSIONS

			x 10^3 tons				
State	1950	1955	1960	1965	1970	1975	1978
			EPA - REGION I				
Conn.	85.7	100.0	152.6	169.0	202.0	182.0	183.0
Maine	44.6	46.7	49.1	60.2	75.8	72.7	76.7
Mass.	164.2	195.0	254.9	303.4	359.9	340.2	364.3
New Hamp.	18.2	22.6	31.1	39.7	63.7	67.5	66.9
Rhode Island	33.5	32.9	45.2	36.4	55.2	44.9	42.4
TOTAL	346.2	397.2	532.9	608.7	756.6	707.3	733.3
			EPA - REGION II				
New York	493.6	606.5	767.0	919.1	1000.3	869.3	908.9
New Jersey	281.5	319.1	362.7	439.1	538.3	462.0	494.4
TOTAL	775.1	925.6	1129.7	1358.2	1538.3	1331.3	1403.3

TABLE C.2.5 HISTORICAL TRENDS IN NO_x EMISSIONS (Cont'd.)

			x 10^3 tons				
State	1950	1955	1960	1965	1970	1975	1978
			EPA - REGION III				
Delaware	19.8	30.1	51.2	61.1	71.9	65.2	70.6
D.C.	30.8	34.3	35.0	38.1	58.3*	36.5	33.5
Maryland	108.9	138.5	222.9	292.5	298.8	294.9	313.9
Penn.	479.1	693.2	1020.2	1143.1	1089.2	1093.1	1120.7
Va.	183.8	228.0	259.9	361.8	433.5	420.8	435.2
West Va.	118.9	217.4	225.0	322.3	346.9	470.8	462.4
TOTAL	941.3	1341.5	1814.2	2218.9	2298.6	2381.3	2436.3
			EPA- REGION IV				
Alabama	172.6	367.0	308.6	448.3	416.1	580.8	473.0
Florida	206.8	263.4	321.5	420.8	552.1	733.2	777.4
Georgia	170.8	198.9	226.9	296.7	398.1	520.5	548.8
Kentucky	145.4	208.0	279.1	377.6	497.2	567.3	563.0
Mississippi	97.1	80.8	151.2	196.4	304.5	243.5	272.8
N.C.	192.0	210.7	290.0	376.2	546.4	568.0	591.0
S.C.	87.4	125.4	150.2	178.2	237.3	253.7	300.2
Tenn.	164.9	232.7	335.9	380.3	467.1	615.5	592.9
TOTAL	1237.0	1686.9	2063.5	2674.5	3418.8	4082.5	4119.1
			EPA - REGION V				
Illinois	600.1	890.4	895.9	1063.7	1119.8	1129.1	1129.9
Indiana	296.6	447.2	584.9	555.2	576.4	631.7	600.6
Mich.	318.3	382.9	587.3	746.4	846.6	840.7	843.1
Minn.	164.7	187.6	240.1	275.5	331.3	370.0	399.6
Ohio	498.2	771.5	960.5	1082.3	1165.1	1221.0	1277.1
Wisc.	196.5	215.4	296.6	367.4	455.0	445.7	473.2
TOTAL	2074.4	2895.0	3565.3	4090.5	4494.2	4638.2	4723.5
			OTHER STATES				
Arkansas	112.6	122.9	115.9	147.6	193.2	171.4	217.9
Iowa	167.2	203.6	216.4	248.1	309.6	308.8	321.0
Louisiana	283.5	330.2	535.8	760.1	1016.9	1072.0	1593.7
Missouri	198.1	251.0	294.6	339.1	424.6	593.6	563.0
Texas	876.5	933.1	1658.0	2044.6	2551.3	2833.9	3309.5

*Questionable data

apparent decrease may be due to errors in the data; however, it should be noted that a 38% reduction in SO_x emissions in the northeast also is observed between 1965 and 1978. Therefore, SO_x emissions appear to have been significantly reduced in the northeast during the past 28 years.

Contrary to the apparent reduction in SO_x emissions noted in the northeast, the states in Region III (mid-Atlantic) have generally maintained about the same level of SO_x emissions. There appears to have been a small steady increase between 1955 and 1970, and a small but steady decline between 1970 and 1978.

The southeastern states exhibit a sharp increase in SO_x emissions between 1950 and 1978 with the data suggesting that this increase may be as high as three to five-fold.

In the midwest (Region V), there appears to have been a significant steady increase in SO_x emissions between 1955 and 1965 and a steady decline in these emissions since 1965. Levels today are about 25% higher than in 1955 in this area of the country.

The states of Arkansas, Iowa, Louisiana, Missouri, and Texas have exhibited a steady increase in SO_2 emissions since 1950. NO_x emissions in Arkansas and Iowa appear to have doubled since 1955, while Louisiana and Missouri appear to have experienced a greater than 50% increase and Texas about 24%.

All the areas examined exhibit significant increases in NO_x emissions over the time period studied. This increase ranges from about a factor of two in the northeast to over three in the south. The trends also indicate that NO_x emissions have increased steadily and did not peak in the mid-1960's as did SO_2 emissions.

C.3 IN CANADA

Data have been developed on historical long-term trends for Canadian sulphur dioxide and nitrogen oxide emissions (1,2). Information on production and fuel consumption on a provincial basis was obtained from other federal government departments for the various sectors investigated. Supplemental data such as the names of specific plants operating in 1955 and 1965 were obtained from internal files and various provincial agencies. For area type sources, where necessary, census information specific to the earlier time periods was used. In many cases, emission factors were applied to the basic data derived from these information sources. The factors used were either from U.S. EPA's data (3), the same factors adapted to Canadian conditions, or Canadian factors developed by Environment Canada. Generally, the methodology adopted for developing emissions for the earlier years closely followed that now being utilized for current emissions (4), except that actual emission data extracted from plant files were utilized for all copper-nickel smelter complexes (2), and for some power generating plants (1).

The years 1955, 1965, and 1976 were chosen to give a fair representation of the trends in emissions over the past three decades. The data for 1955 and 1965 were developed on a national, provincial, and census division basis for all of Canada and for those sectors which, as a whole, are thought to contribute more than 90 percent of total emissions of SO_2 and NO_x. The data for 1976 have been developed in many formats - nationally, provincially, on a census division basis, on a 127 km x 127 km grid basis, and on a major metropolitan area basis - and cover the full spectrum of point and area types of emission sources (more than 70 sectors of the Canadian economy).

Total Canadian emissions of SO_2 and NO_x for each of the years 1955, 1965, and 1976 are presented in Table C.3.1 for the sectors of most concern at this time. Table C.3.2 presents the same information but for eastern Canada only. Total SO_2 emissions in Canada in 1976 were approximately 5.4 million tonnes, compared with 6.2 million tonnes in 1965 and 4.4 million tonnes in 1955. This fluctuation was largely due to significant changes in the emissions from the copper-nickel smelting industry which represented 65%, 62%, and 47% of total SO_2 emissions in the years 1955, 1965, and 1976 respectively. Eastern Canada has always contributed the larger portion of national emissions, this share being about 96%, 87%, and 83% in the years 1955, 1965, and 1976. All copper-nickel smelting complexes are located in eastern Canada (including Manitoba).

Emissions of SO_2 from power plants were at a negligible level of less than 0.1 million tonnes in 1955 before increasing to 0.2 million tonnes in 1965 and

TABLE C.3.1 HISTORICAL EMISSIONS OF SO_2 AND NO_x - CANADA

Sector	Emissions (tonnes)					
	1955		1965		1976	
	SO_2	NO_x (1)	SO_2	NO_x (1)	SO_2	NO_x (1)
Cu-Ni smelters	2 870 000	-	3 827 000	-	2 540 657	-
Power plants	52 502	11 155	224 931	52 779	614 323	206 454
Other combustion*	974 360	212 451	671 218	192 185	997 139	473 317
Transportation** (gasoline-powered motor vehicles)	N/A (4 687)	N/A (63 447)	N/A (9 938)	N/A (208 681)	77 793 (19 469)	1 017 936 (506 691)
Iron ore processing	109 732	-	155 832	-	175 829	-
Others	381 423	17 751	1 262 534	37 262	1 018 195	190 327
TOTAL	4 392 704	304 804	6 151 453	490 907	5 423 936	1 888 034

* Includes residential, commercial and industrial fuel combustion.

** Historical data for transportation sectors other than gasoline-powered motor vehicles have not yet been developed for 1955 and 1965.

(1) NO_x expressed as NO_2.

N/A Not available

TABLE C.3.2 HISTORICAL EMISSIONS OF SO_2 AND NO_x - EASTERN CANADA

	Emissions (tonnes)					
	1955		1965		1976	
Sector	SO_2	NO_x (1)	SO_2	NO_x (1)	SO_2	NO_x (1)
Cu-Ni smelters	2 870 000	-	3 827 000	-	2 540 657	-
Power plants	51 236	7 870	218 128	42 485	554 417	142 470
Other combustion*	900 861	172 952	634 603	149 764	905 159	280 539
Transportation** (gasoline-powered motor vehicles)	N/A (3 449)	N/A (46 640)	N/A (7 239)	N/A (152 012)	52 827 (13 237)	652 737 (347 294)
Iron ore processing	109 732	-	155 832	-	175 829	-
Others	272 416	11 905	493 320	27 002	271 933	94 763
TOTAL	4 207 694	239 367	5 336 122	371 263	4 500 822	1 170 509
(% of the total Canada)	(96%)	(79%)	(87%)	(76%)	(83%)	(62%)

* Includes residential, commercial and industrial fuel combustion.

** Historical data for transportation sectors other than gasoline-powered motor vehicles have not yet been developed for 1955 and 1965.

(1) NO_x expressed as NO_2

N/A Not available

reaching 0.6 million tonnes in 1976. Close to 90% of this total was emitted within eastern Canada.

Sulphur dioxide emissions from the combustion of fuels for industrial, commercial, and residential purposes decreased from 1955 to 1965, largely because of the switch away from coal as the primary fuel, before increasing and reaching in 1976 levels comparable to those of 1955, i.e., about 1.0 million tonnes, because of greater activity in the industrial market. In 1976, about 75% of other combustion emissions were from industrial fuel combustion sources. In 1955 and 1965 this contribution was closer to two-thirds of the total emissions. SO_2 emissions from transportation sources in 1976 were about equally due to gasoline-powered motor vehicles, diesel-powered engines, and railroads. Emissions from gasoline-powered motor vehicles quadrupled from 1955 to the mid-1970's.

The iron ore processing sector contributed close to 0.2 million tonnes of SO_2 in 1976, i.e., about twice the level of 1955. Such processing involves the mining and beneficiation of the ore by sintering or pelletizing operations to produce a suitable blast furnace feed. Other industrial processes, included under "others" in Tables C.3.1 and 2, saw their SO_2 emissions increase from 0.4 million tonnes in 1955 to 1.0 million tonnes in 1976 due largely to increased productivity in various sectors of the economy. Three-quarters of these emissions came from western Canada.

It is difficult to measure the uncertainty of the SO_2 inventories for 1955 and 1965. However, because of the source of the data used to estimate emissions from copper-nickel smelter complexes (2), and the fact that this sector contributes significantly to total emissions, the confidence level of the historical emissions inventory of SO_2 is greatly increased. An analysis made of the 1976 inventory has indicated that the overall SO_2 inventory for Canada is accurate within ± 30% of the true value at a 75% confidence level (2).

A map of eastern Canada divided on the basis of 127 km x 127 km grid cells, along with an indication of the magnitude of 1976 SO_2 emissions for each cell according to five ranges of emissions, is presented in Appendix 2.

Total emissions of NO_x have increased significantly, from a level of 0.3 million tonnes in 1955 to 1.9 million tonnes in 1976, due largely to increases in power plant and transportation sector emissions. The increase in demand for power and electricity has resulted in the building of more power plants, causing NO_x emissions to reach a level of 0.2 million tonnes in 1976, compared to much less than 0.05 million tonnes in 1955, and 0.05 million tonnes in 1965. Gasoline-powered motor vehicle NO_x emissions were about eight times greater in 1976 than in 1955, and were at an even level with other transportation source emissions, the majority of which are attributable to diesel-powered engines. NO_x emissions from other combustion sources have approximately doubled over the period investigated.

The distribution of NO_x emissions between eastern and western Canada is more uniform than the distribution of SO_2 emissions because of the nature of the sources involved. Eastern Canada (including Manitoba) has contributed 79%, 76%, and 62% of total NO_x emissions in 1955, 1965, and 1976 respectively. An uncertainty analysis has not been carried out for NO_x emissions for any of the years of investigation.

A map depicting NO_x emissions in eastern Canada in 1976 according to the 127 km x 127 km grid array is presented in Appendix 2.

REFERENCES (SECTION C.3)

1. Environment Canada, Air Pollution Control Directorate, Data Analysis Division (Unpublished Information) (December 1980).

2. Environment Canada, Air Pollution Control Directorate, Copper-Nickel Smelter Complexes in Canada, SO_2 Emissions (1950-2000), Report EPS 3-AP-80-5 (January 1981).

3. EPA Publication AP-42, "Compilation of Air Pollutant Emission Factors", third edition, August 1977.

4. Environment Canada, Air Pollution Control Directorate, A Nationwide Inventory of Emissions of Air Contaminants (1976), Report EPS-3-AP-80-1 (January 1981).

5. Environment Canada, Air Pollution Control Directorate, National Inventory of Natural Sources and Emissions of Sulphur Compounds, Report EPS 3-AP-79-2 (February 1980).

6. Environment Canada, Air Pollution Control Directorate, National Inventory of Natural Sources and Emissions of Nitrogen Compounds, Report EPS 3-AP-80-4 (January 1981).

D. PRESENT EMISSION RATES

This chapter provides estimates of current emissions of SO_2 and NO_x in both the United States and Canada. The data for U.S. emissions are current as of 1978, while the data for Canadian emissions are for various years. Canadian SO_2 emissions are current for 1979 with one major point source current for 1980. Canadian NO_x emissions are current for 1977. It is hoped that all emission estimates can be updated to 1979 values for the final version of this report.

D.1 In the United States

The current emission rates reported here for the United States are based on estimates of actual rates for numerous sectors of the economy. The values used in this summary are taken from National Air Pollution Emission Estimates (U.S. Environmental Protection Agency). Basically, the methodology for deriving these estimates uses an inventory of sources, determination of fuel consumption, and air pollution emission factors.

The inventory of sources, and associated fuel consumption rates, were taken from the National Emissions Data System (NEDS). The data in NEDS were provided by state agencies as an inventory of sources for each state. NEDS is constantly being updated and the version used here reflects values in the system for February, 1980. However, NEDS is not complete and some source categories are more accurate than others. Estimates of the accuracy of this information are unavailable at this time.

The emission factors used in developing these emission estimates are from the U.S. EPA data (1). The emission factor is an average estimate of the rate at which a pollutant is released to the atmosphere as a result of some activity, such as combustion or industrial production, divided by the level of that activity. The emission factors are estimates based on source testing, process material balances, and engineering appraisals. As a result, some emission factors are more accurate than others. In general, the emission factors are more often applied to regional or national emission estimates, as in this report, than to single source estimates where the inaccuracies would be considerable.

Total emissions of SO_2 and NO_x for 1978 are shown in Table D.1.1, segmented for various categories of sources. Clearly, the largest source category of SO_2 emission in the United States is the utility category. Utilities account for approximately two-thirds of the SO_2 emissions. Other stationary sources contribute nearly one-third, with the remainder from transportation sources. In terms of total NO_x emissions, the transportation sector is the primary source, contributing 40%, with utility and industrial boilers emitting 52%.

SO_2 and NO_x emissions can be disaggregated on a state-by-state basis, as shown in Table D.1.2. Only 33 states are represented in the table. Data for the 15 western states and Alaska and Hawaii are unavailable at this time. The values in Table D.1.2 represent 80% of the SO_2 and 76% of the NO_x emissions for the entire United States.

The emission estimates can be further disaggregated to show emissions by source catagory for each state. Tables D.1.3 through D.1.8 show this information based on 1977 data.

Information on natural sources of sulfur and nitrogen emissions in the United States is not available at this time.

REFERENCES

1. EPA Publication AP-42, "Compilation of Air Pollutant Emission Factors", third edition, August 1977.

TABLE D.1.1 CURRENT (1978) EMISSIONS OF SO_2 AND NO_x - U.S. (10^6 tonnes)

Category	SO_2 (% of total)		NO_x (% of total)	
Utilities	17.6	(65%)	7.2	(31%)
Industrial Boilers	3.2	(12%)	4.9	(21%)
Industrial Processes	4.1	(15%)	0.8	(3.5%)
Transportation	0.8	(3%)	9.4	(40%)
Residential/Commercial	1.3	(5%)	0.8	(3.5%)
Solid Waste Disposal	0.0	(0%)	0.1	(0.5%)
Miscellaneous	0.0	(0%)	0.1	(0.5%)
Total	27.0	(100%)	23.3	(100%)

TABLE D.1.2 1978 SO_2 AND NO_x EMISSIONS BY STATE (10^3tons)

State	SO_2	NO_x
Alabama	762.1	473.0
Arkansas	121.6	217.9
Connecticut	112.0	183.0
Delaware	188.2	70.6
District of Columbia	17.6	33.5
Florida	685.9	777.4
Georgia	707.0	548.8
Illinois	1747.2	1129.9
Indiana	1848.2	600.6
Iowa	385.0	321.0
Kentucky	1330.0	563.0
Louisiana	359.0	1593.7
Maine	66.0	76.7
Maryland	357.3	313.9
Massachusetts	402.2	364.3
Michigan	1117.8	843.1
Minnesota	379.0	399.6
Mississippi	264.3	272.8
Missouri	1307.7	563.0
New Hampshire	67.8	66.9
New Jersey	323.7	494.4
New York	1041.1	908.9
North Carolina	562.3	591.0
Ohio	3115.3	1277.1
Pennsylvania	1900.0	1120.7
Rhode Island	19.7	42.4
South Carolina	288.6	300.2
Tennessee	1162.8	592.9
Texas	1244.8	3309.5
Vermont	-	-
Virginia	359.9	435.2
West Virginia	1049.5	462.4
Wisconsin	663.6	473.2
TOTAL	23957.2	19420.6
	or 21.73 million tonnes	17.62 million tonnes

TABLE D.1.3 1977 U.S. EMISSIONS - UTILITIES (10^3 tons)

	SO_2	NO_x
National*	19797	7.284
Alabama	780	213
Alaska	2.3	6.0
Arizona	75	136
Arkansas	50	34
California	185	174
Colorado	74	75
Connecticut	51	42
Delaware	82	28
District of Columbia	10	8
Florida	757	211
Georgia	578	140
Hawaii	39	21
Idaho	0.011	0.024
Illinois	1369	602
Indiana	1493	462
Iowa	234	83
Kansas	125	146
Kentucky	1526	346
Louisiana	59	183
Maine	10	3
Maryland	228	77
Massachusetts	143	88
Michigan	9.2	230
Minnesota	175	81
Mississippi	179	53
Missouri	1265	315
Montana	24	34
Nebraska	28	33
Nevada	35	87
New Hampshire	92	36
New Jersey	127	83
New Mexico	145	118
New York	508	262
North Carolina	426	195
North Dakota	83	48
Ohio	2688	529
Oklahoma	3	101
Oregon	0	0
Pennsylvania	1476	391
Rhode Island	3.6	2.6
South Carolina	181	97
South Dakota	33	23
Tennessee	1091	229
Texas	249	490
Utah	44	24

TABLE D.1.3 1977 U.S. EMISSIONS - UTILITIES (10^3 tons) (Cont'd)

	SO_2	NO_x
Vermont	0.007	0.015
Virginia	259	104
Washington	18	51
West Virginia	1048	263
Wisconsin	470	128
Wyoming	129	99

TABLE D.1.4 1977 U.S. EMISSIONS - INDUSTRIAL BOILERS (10^3 tons)

	SO_2	NO_x
National*	3254.7	1846.4
Alabama	101	41
Alaska	3	3
Arizona	3	4
Arkansas	37	20
California	135	98
Colorado	7	3
Connecticut	6	6
Delaware	12	4
District of Columbia	4	2
Florida	67	38
Georgia	50	25
Hawaii	11	2
Idaho	6	14
Illinois	101	51
Indiana	154	123
Iowa	48	27
Kansas	2	14
Kentucky	43	17
Louisiana	78	217
Maine	94	23
Maryland	31	21
Massachusetts	70	51
Michigan	124	69
Minnesota	47	21
Mississippi	16	15
Missouri	20	8
Montana	10	6
Nebraska	2	5
Nevada	2	3
New Hampshire	16	3
New Jersey	36	33
New Mexico	9	5
New York	198	52
North Carolina	97	32
North Dakota	4	2
Ohio	325	125
Oklahoma	5	5
Oregon	15	38
Pennsylvania	520	84
Rhode Island	6	2
South Carolina	83	33
South Dakota	0	0
Tennessee	94	53
Texas	123	232
Utah	14	8

TABLE D.1.4 1977 U.S. EMISSIONS - INDUSTRIAL BOILERS (10^3 tons) (Cont'd)

	SO_2	NO_x
Vermont	0.6	0.5
Virginia	115	40
Washington	49	38
West Virginia	89	97
Wisconsin	112	43
Wyoming	12	6

TABLE D.1.5 1977 U.S. EMISSIONS - INDUSTRIAL PROCESSES (10^3 tons)

	SO_2	NO_x
National*	5636.8	1020.5
Alabama	108	24
Alaska	0	0.4
Arizona	1132	4
Arkansas	26	2
California	219	129
Colorado	19	4
Connecticut	0.5	0.1
Delaware	31	3
District of Columbia	0	0
Florida	115	24
Georgia	29	12
Hawaii	10	3
Idaho	31	.7
Illinois	126	45
Indiana	60	29
Iowa	36	4
Kansas	46	20
Kentucky	18	9
Louisiana	177	122
Maine	14	2
Maryland	53	16
Massachusetts	1	0
Michigan	133	17
Minnesota	26	4
Mississippi	32	13
Missouri	141	17
Montana	162	4
Nebraska	14	4
Nevada	286	3
New Hampshire	0.9	0.3
New Jersey	67	20
New Mexico	408	7
New York	46	9
North Carolina	35	7
North Dakota	20	0.9
Ohio	90	20
Oklahoma	92	12
Oregon	12	2
Pennsylvania	355	41
Rhode Island	0	0
South Carolina	21	7
South Dakota	4	1
Tennessee	60	15
Texas	878	193
Utah	131	10

TABLE D.1.5 1977 U.S. EMISSIONS - INDUSTRIAL PROCESSES (10^3 tons) (Cont'd)

	SO_2	NO_x
Vermont	0	0
Virginia	24	14
Washington	171	23
West Virginia	58	12
Wisconsin	41	47
Wyoming	21	5

TABLE D.1.6 1978 U.S. EMISSIONS - TRANSPORTATION (tonnes)

	TSP	SO_x	NO_x	HC	CO
National	6 286 087	955 767	9 355 943	12 549 131	97 801 165
Alabama	110 642	25 892	205 541	241 841	1 754 292
Arkansas	63 752	9 921	128 555	144 749	1 049 778
Connecticut	81 687	6 622	100 103	152 975	1 235 652
Delaware	16 283	2 823	28 039	35 773	275 377
Dist. of Columbia	15 214	1 197	17 111	24 236	202 223
Florida	298 590	30 889	362 730	557 336	4 269 119
Georgia	155 564	20 212	270 023	323 335	2 430 711
Illinois	286 008	30 472	398 479	518 854	4 112 325
Indiana	155 893	18 838	255 218	320 855	2 519 201
Iowa	60 897	9 805	135 773	157 697	1 218 841
Kentucky	90 950	14 480	189 160	204 932	1 508 128
Louisiana	113 812	43 953	202 170	240 994	1 754 474
Maine	23 288	3 727	50 419	59 136	428 545
Maryland	113 453	14 735	152 485	207 733	1 609 040
Massachusetts	158 713	10 765	161 017	278 951	2 314 969
Michigan	269 852	46 761	350 936	482 683	3 869 142
Minnesota	103 899	14 320	198 444	254 163	1 947 578
Mississippi	53 514	12 257	123 978	129 197	943 935
Missouri	151 023	17 041	235 436	306 040	2 367 375
New Hampshire	21 252	1 627	29 361	41 446	330 945
New Jersey	221 443	27 381	248 805	375 900	3 069 379
New York	340 260	34 575	419 157	634 875	5 114 336
North Carolina	143 885	19 465	284 714	334 094	2 477 393
Ohio	321 708	36 835	433 805	507 312	4 582 071
Pennsylvania	282 530	38 405	435 991	531 822	4 196 933
Rhode Island	28 369	1 679	29 380	53 827	444 384
South Carolina	76 807	9 897	136 873	173 858	1 258 446
Tennessee	129 395	19 505	250 647	274 032	2 038 819
Texas	455 232	111 334	704 565	897 667	6 744 339
Vermont	9 794	1 383	21 363	22 453	162 963
Virginia	135 464	19 047	237 600	286 300	2 147 609
West Virginia	17 147	5 663	69 521	51 699	326 512
Wisconsin	87 749	13 941	198 364	231 296	1 657 454

SOURCE: National Emissions Data System (NEDS).

TABLE D.1.7 1978 U.S. EMISSIONS - COMMERCIAL/RESIDENTIAL (tonnes)

	TSP	SO_x	NO_x	HC	CO
National	353 760	23 406	100 672	742 054	2 152 169
Alabama	8 504	407	2 314	18 286	18 285
Arkansas	4 249	259	1 375	8 417	23 968
Connecticut	3 202	131	686	7 103	20 738
Delaware	640	53	229	1 064	29 089
Dist. of Columbia	612	179	214	477	7 482
Florida	65 291	1 126	1 870	9 906	28 251
Georgia	7 298	445	2 646	13 833	39 126
Illinois	16 606	1 186	2 981	39 490	116 353
Indiana	12 438	877	3 718	25 938	75 007
Iowa	8 324	634	2 134	17 083	49 374
Kentucky	5 927	398	2 192	11 170	32 107
Louisiana	5 739	287	1 723	11 753	33 316
Maine	2 719	182	776	5 579	16 072
Maryland	3 806	257	1 351	7 199	20 439
Massachusetts	7 794	420	1 501	17 869	52 370
Michigan	19 415	2 508	15 557	41 699	115 990
Minnesota	11 634	426	2 211	18 010	52 287
Mississippi	6 360	339	1 831	13 403	38 451
Missouri	10 158	429	2 100	23 533	68 831
New Hampshire	1 836	123	505	3 799	10 965
New Jersey	10 063	2 074	3 348	12 415	33 673
New York	16 216	1 453	4 718	27 866	79 280
North Carolina	11 169	865	4 106	20 296	57 248
Ohio	21 098	13 046	4 789	45 654	132 856
Pennsylvania	4 473	1 291	1 531	1 832	15 499
Rhode Island	1 187	48	208	2 866	8 403
South Carolina	7 676	390	2 230	16 185	46 695
Tennessee	9 366	507	2 601	20 165	59 487
Texas	12 820	784	3 539	26 742	76 609
Vermont	1 479	95	444	2 995	8 690
Virginia	6 786	590	2 547	12 661	35 788
West Virginia	3 947	237	1 434	7 505	21 235
Wisconsin	11 907	995	3 208	23 524	67 860

SOURCE: National Emissions Data System (NEDS).

TABLE D.1.8 1977 U.S. EMISSIONS - SOLID WASTE DISPOSAL (10^3 tons)

	SO_2	NO_x
National	51	138
Alabama	0.4	2.7
Alaska	0.0	0.5
Arizona	0.7	2.2
Arkansas	0.5	1.9
California	1.2	5.3
Colorado	0.2	0.8
Connecticut	0.2	0.8
Delaware	0.1	0.3
District of Columbia	0.6	0.6
Florida	1.6	3.1
Georgia	0.5	3.1
Hawaii	0.2	0.4
Idaho	0.1	0.7
Illinois	1.3	3.1
Indiana	1.2	4.2
Iowa	0.7	2.2
Kansas	0.3	1.4
Kentucky	0.9	3.0
Louisiana	3.3	2.7
Maine	0.5	2.5
Maryland	0.6	1.7
Massachusetts	1.7	4.5
Michigan	2.9	16.4
Minnesota	0.5	2.3
Mississippi	0.5	2.6
Missouri	0.9	2.5
Montana	0.1	0.7
Nebraska	0.3	1.4
Nevada	2.0	2.5
New Hampshire	0.3	1.5
New Jersey	2.0	3.2
New Mexico	0.2	0.7
New York	5.3	8.4
North Carolina	1.5	5.7
North Dakota	0.1	0.5
Ohio	2.4	6.7
Oklahoma	0.2	6.7
Oregon	0.3	1.6
Pennsylvania	2.3	6.3
Rhode Island	0.1	0.3
South Carolina	0.4	2.4
South Dakota	0.1	0.7
Tennessee	1.4	3.6
Texas	7.0	5.3
Utah	0.2	0.5
Vermont	0.1	0.4

TABLE D.1.8 1977 U.S. EMISSIONS - SOLID WASTE DISPOSAL (10^3 tons) (Cont'd)

	SO_2	NO_x
Virginia	1.0	3.1
Washington	0.5	2.1
West Virginia	0.3	1.6
Wisconsin	1.4	3.9
Wyoming	0.1	0.4

D.2 IN CANADA

The Canadian data base includes estimates of actual emissions for more than 70 sectors of the economy. The methodology used to derive these estimates is described in detail for each of the sectors investigated in Reference 1. Basically, for point source types of emissions, substantial information is extracted from government surveys made of individual plants or installations and often based on stack testing at the source. In other cases where such firsthand information is not available, and for area source types of emissions, the emission factor approach is used. In these instances, either U.S. EPA emission factors (2), or these factors corrected for Canadian conditions, or emission factors developed by Environment Canada are utilized. Information regarding production and fuel consumption by the various sources comes from other federal government departments and is supplemented by data from a number of industrial associations.

On a national basis the overall accuracy of the current Canadian SO_2 emissions inventory is estimated to be ± 30% at a 75% confidence level (3). The accuracy of the information varies widely between each sector, and within each sector investigated; it is far greater for the major point sources (e.g., Cu-Ni smelters), which together represent more than half of Canadian emissions, than for less significant sources. An uncertainty analysis has not been carried out for NO_x emissions, but as a first approximation, the overall accuracy of the NO_x data base is less than that of the SO_2 data because the important contributors of such emissions (e.g., transportation sources) are quite different.

The data base for present emission rates in Canada includes a mixture of data covering the period 1976 through 1980. For sulphur dioxide all area source information represents 1976 annual emission rates (1). Major point sources are at their 1979 annual emission rates and the most important Canadian copper-nickel smelter complex, representing fully 20% of eastern Canada emissions, is shown at its 1980 emission rate (3). On a weighted emissions basis, the aggregated SO_2 data base closely represents actual emissions for the year 1979.

For nitrogen oxides, all area source type emissions are from the 1976 base year (1). Major point sources are at their 1979 annual emission rate (3). On a weighted emission basis, the aggregated Canadian NO_x data base probably represents actual emission rates in 1977.

Table D.2.1 gives the total national emissions for SO_2 and NO_x prorated on the basis of the usual five categories of emission sources. Roughly two-thirds of SO_2 emissions in Canada are contributed by industrial processes; the other third results

TABLE D.2.1 CURRENT (1976-1980) EMISSIONS OF SO_2 AND NO_x - CANADA

	Emissions (tonnes)			
Category	SO_2	(% of total)	NO_x [(1)]	(% of total)
Industrial processes	3 085 412	(63.4%)	38 213	(2.0%)
Fuel combustion/ stationary sources	1 698 683	(34.9%)	693 675	(36.5%)
Transportation	77 793	(1.6%)	1 017 936	(53.5%)
Solid waste incineration	3 245	(0.1%)	5 094	(0.3%)
Miscellaneous	-		147 020	(7.7%)
TOTAL	4 865 133	(100%)	1 901 938	(100%)

(1) NO_x expressed as NO_2.

TABLE D.2.2 CURRENT (1976-1980) EMISSIONS OF SO_2 AND NO_x - EASTERN CANADA

	Emissions (tonnes)			
	SO_2	(% of total)	NO_x [(1)]	(% of total)
Cu-Ni smelters	2 021 201	(49.4%)	-	
Power plants	641 638	(15.7%)	156 374	(13.2%)
Other combustion*	905 159	(22.1%)	280 539	(23.7%)
Transportation (gasoline-powered motor vehicles)	52 827 (13 237)	(1.3%)	652 737 (347 294)	(55.1%)
Iron ore processing	198 480	(4.9%)	-	
Others	271 933	(6.6%)	94 763	(8.0%)
TOTAL	4 091 238		1 184 413	
(% of total Canada)		(84%)		(62%)

* Includes residential, commercial and industrial fuel combustion.

(1) NO_x expressed as NO_2.

from the combustion of fuels in stationary sources. This latter category of sources is also responsible for about one-third of the total NO_x emissions in Canada. Transportation sources account for more than half of NO_x emissions and close to 50% of this is due to the gasoline-powered motor vehicle alone. From 1976 to 1979-80, there was a reduction of about 10% in total Canadian SO_2 emissions which was largely due to a significant drop in non-ferrous smelter emissions.

Table D.2.2 presents total emissions for eastern Canada only (east of the Manitoba-Saskatchewan border) over the 1976-80 period for the sectors of most concern at this time. Eastern Canada's emissions account for close to 85% of total SO_2 emissions and about two-thirds of NO_x emissions. Close to half (49%) of the SO_2 emissions in eastern Canada are concentrated in six copper-nickel smelters located in Manitoba, Ontario and Quebec. About one quarter of the SO_2 emissions result from the combustion of fuels for industrial, commercial, and residential purposes; the industrial source contributes about 75% of these emissions (1). Power plants are responsible for a little more than 15% of eastern Canada SO_2 emissions and close to three-quarters of such emissions come from power plants located in southern Ontario (1,3). Iron ore processing, i.e., the mining and beneficiation of ores by sintering or pelletizing operations, is responsible for close to 5% of eastern Canada SO_2 emissions.

A large part (55%) of eastern Canada's NO_x emissions is contributed by transportation sources. Here, gasoline-powered motor vehicles, diesel-powered engines and railroads contribute about half, one-third, and 10%, respectively of such emissions (1). The second major sector of NO_x emissions in eastern Canada is the combustion of fuels in industrial, commercial, and residential applications. This sector contributes about one-quarter of NO_x emissions (same contribution as for SO_2 emissions); 59% of the sector's emissions come from industrial fuel combustion sources (1). This is followed by power plants, which generate about 13% of eastern Canada's NO_x emissions, two-thirds of which are from southern Ontario installations (1,3).

The eastern Canada data are further prorated on a grid array of 127 km x 127 km squares, which is the basic dimension for the emissions and meteorological data used in the Atmospheric Environment Service long-range transport model. Total (point and area) emissions of SO_2 and NO_x, for each of the grid cells in eastern Canada, are listed in Appendix 2. Figure D.2.1 and Table D.2.3 present an aggregated version of the SO_2 data found in Appendix 2. Here, the geographical area representing eastern Canada has been divided into 17 defined source regions, delineated by the boundaries of the 127-km grid cells. These source regions have been defined to represent

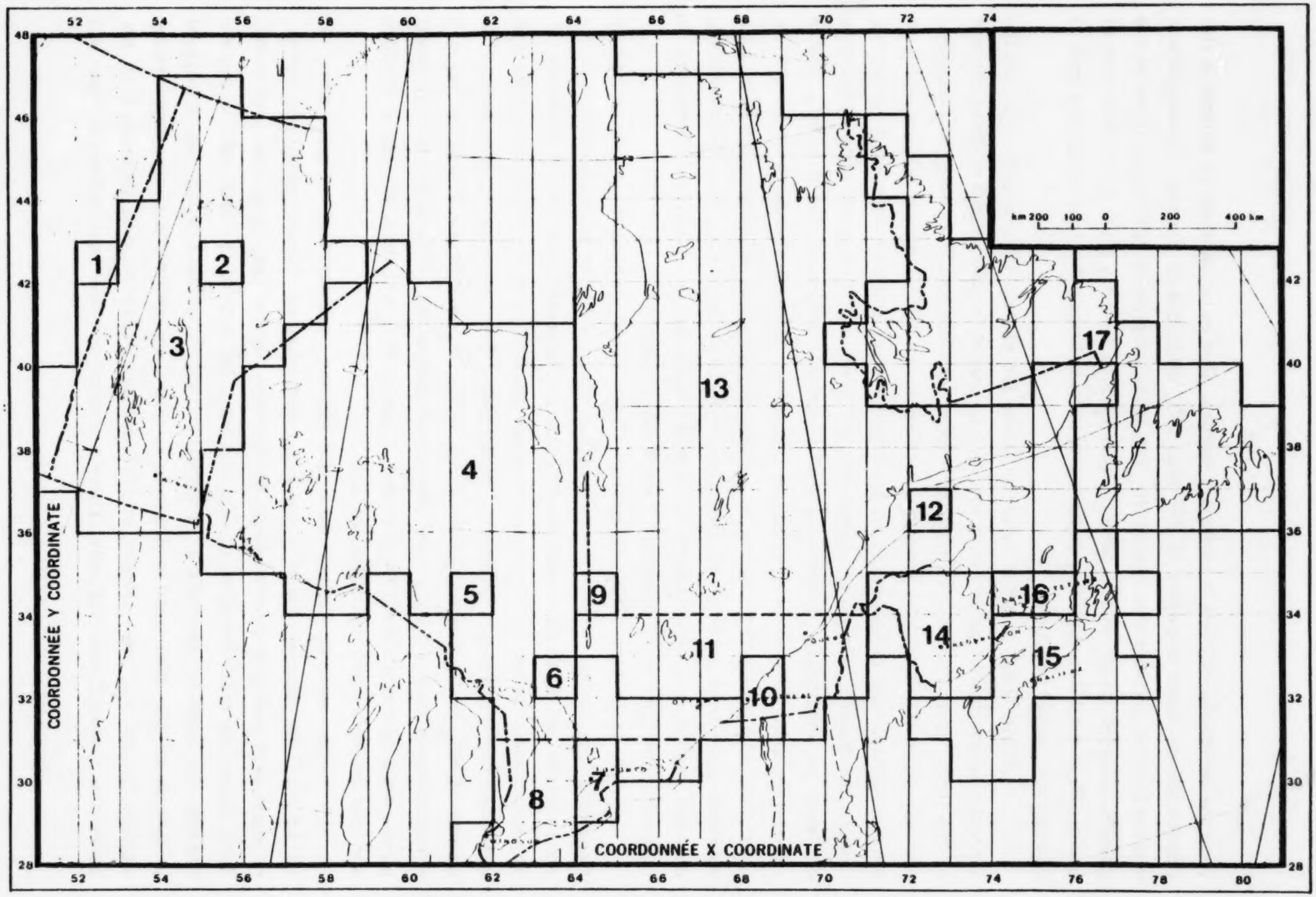

FIGURE D.2.1

DEFINED CANADIAN SOURCE REGIONS · 127 km × 127 km GRID
RÉGIONS SOURCES CANADIENNES DÉFINIES · GRILLE DE 127 km × 127 km

TABLE D.2.3 SO_2 EMISSIONS FROM DEFINED CANADIAN SOURCE REGIONS - 1976-80 DATA BASE

Source Region	Map Identifier	Emissions (tonnes x 10^3)
Flin Flon, Manitoba	1	152.2
Thompson, Manitoba	2	334.0
Manitoba (excluding 1 & 2)	3	27.1
Northern Ontario (excluding 5 & 6)	4	76.6
Wawa, Ontario	5	182.3
Sudbury area, Ontario	6	1 006.9
Toronto region, Ontario*	7	245.2*
Southern Ontario (excluding 7)	8	440.6
Noranda, Quebec	9	540.7
Montreal region, Quebec**	10	292.5**
Southern Quebec (excluding 10)	11	96.3
Murdochville, Quebec	12	73.1
Northern Quebec (excluding 9 & 12)	13	83.5
New Brunswick	14	199.5
Nova Scotia	15	213.8
Prince Edward Island	16	19.0
Newfoundland and Labrador	17	54.3
TOTAL		4 037.6

* Metro-Toronto only = 207.0 x 10^3 tonnes
** Metro-Montreal only = 261.1 x 10^3 tonnes

TABLE D.2.4 SEASONAL VARIATIONS IN CANADIAN SO_2 AND NO_x EMISSIONS

	% of annual emissions							
	December-February		March-May		June-August		September-November	
Category	SO_2	NO_x	SO_2	NO_x	SO_2	NO_x	SO_2	NO_x
Industrial processes	27	25	25	25	23	25	25	25
Fuel combustion/ stationary sources	34	34	22	22	18	19	26	25
Transportation	22	24	25	25	27	26	26	25
Incineration	25	25	25	25	25	25	25	25
Miscellaneous	-	-	-	21	-	77	-	1
Total (weighted)	29	25	24	23	22	28	25	24

either major point sources, areas comprising large metropolitan centres, or significant geographic portions of provinces.

Seasonal variations data for use in detailed air quality analysis have been developed for both SO_2 and NO_x emissions for all contributing sectors (3). In summary, emissions are found to vary considerably from season to season for the fuel combustion sectors, the winter (December - February) emissions being about 85% greater than the summer (June - August) emissions. The other categories show little variation; for example, the overall winter emissions from industrial processes are about 15% greater than the summer emissions. The national summary is presented in Table D.2.4

Nationwide inventories of natural emissions of sulphur and nitrogen compounds into the atmosphere and an evaluation of their contribution to the overall sulphur and nitrogen burden of ambient air have been carried out for Canada (4,5). Data on estimates of natural emissions were obtained through a literature review of sulphur and nitrogen release mechanisms normally associated with biological and other natural processes. Such data are relatively sparse and in some cases contradictory, making some reported estimates of source emissions quite speculative. The emission estimates are likely to be accurate only to within an order of magnitude.

The principal sulphur compound emitted by biological processes into the atmosphere is hydrogen sulphide. Others that have been identified include: carbon disulphide, carbonyl sulphide, dimethyl disulphide and methyl mercaptan. Biogenic sources include soils, water bodies, and vegetation. Forest fires emit sulphur dioxide while sea and lake sprays release sulphates. The total emissions of sulphur from natural sources in Canada are estimated at about 500 000 tonnes per year, (i.e., about 20% of total anthropogenic emissions of sulphur dioxide). The greatest natural sulphur emissions occur on the Atlantic and Pacific coasts and in Ontario and Quebec. Table D.2.5 summarizes this information.

Included in the more important nitrogenous compounds emitted to the atmosphere from natural sources are N_2O, NO_x, NH_3, and aliphatic amines. Principal emitting sources are soils and marine waters for N_2O, soils and lightning for NO_x, soils and animal wastes for NH_3, and animal wastes for aliphatic amines. Nitrogen oxides emitted from forest fires are less important. The total emissions of nitrogen from natural sources in Canada are estimated at about 2 100 000 tonnes per year, (i.e., roughly three and one half times the total anthropogenic emissions of nitrogen oxides (expressed as NO_2)). Table D.2.6 summarizes the information on emissions of natural nitrogen compounds in Canada.

TABLE D.2.5 SUMMARY OF NATURAL EMISSIONS OF SULPHUR INTO THE ATMOSPHERE IN CANADA (tonnes of S per year)(1)

Province/Territory	Biogenic Emissions				Other Natural Sources*		
	Soils	Marine	Lakes	Vegetation	Sea Salt SO_4	Soil Dust	Forest Fires
Newfoundland	2 187		203	138			81
Prince Edward Island	72		-	200			
Nova Scotia	609		102	226			3
New Brunswick	761		100	278			5
Quebec	23 888	36 692**	1 471	1 772	101 200**		60
Ontario	65 672	4 381	3 543	2 698			55
Manitoba	47 860		2 650	552			203
Saskatchewan	17 217		2 434	1 245			164
Alberta	31 062		654	1 016			64
British Columbia	29 515	10 465	810	782	27 300	500****	171
Yukon	4 950						
Northwest Territories	22 770	92***			60 400***		194
Canada	246 563	51 631	11 967	8 907	188 900	500	1 000

Canadian total - 509 406 tonnes

*	Does not include 7 tonnes from lake sulphate.
**	Includes Atlantic Provinces and Quebec.
***	Includes Yukon and Northwest Territories.
****	Includes Saskatchewan, Alberta and British Columbia.
(1)	All above figures expressed as tonnes of S per year. To get the equivalent SO_2 emissions, above figures must be multiplied by 2 (for example, total Canadian natural sulphur emissions expressed as SO_2 are 509 406 x 2 = 1 018 812 tonnes).

TABLE D.2.6 SUMMARY OF NATURAL EMISSIONS OF NITROGEN INTO THE ATMOSPHERE IN CANADA (tonnes of N per year)(1)

Province/Territory	Compound Class				
	N_2O	NO_x	NH_3	Amines	Total
Newfoundland	40 801	52 484	1 975	61	95 321
Nova Scotia	9 032	12 038	2 981	48	24 099
Prince Edward Island	1 279	1 748	1 143	62	4 232
New Brunswick	12 236	16 300	4 217	64	32 817
Quebec	168 315	212 196	18 044	576	399 131
Ontario	135 070	165 878	52 432	974	354 354
Manitoba	70 686	75 917	61 279	408	208 290
Saskatchewan	69 539	68 665	130 740	1 900	270 844
Alberta	45 614	39 485	115 228	1 278	201 605
British Columbia	69 832	72 108	99 474	550	241 964
Yukon	18 739	15 281	8 389	106	42 515
Northwest Territories	97 759	91 328	33 393	336	222 816
Canada	738 902	823 428	529 295	6 363	2 097 988

(1) All above figures expressed as tonnes of N per year. To get the equivalent NO_2 emissions, above figures must be multiplied by 46/14 (for example, total Canadian natural nitrogen emissions expressed as NO_2 are 2 097 988 x 46/14 = 6 893 389 tonnes).

References (Section D.2)

1. Environment Canada, Air Pollution Control Directorate, A Nationwide Inventory of Emissions of Air Contaminants (1976), Report EPS-3-AP-80-1 (January 1981).

2. EPA Publication AP-42, "Compilation of Air Pollutant Emission Factors", third edition, August 1977.

3. Environment Canada, Air Pollution Control Directorate, Data Analysis Division (Unpublished Information) (December 1980).

4. Environment Canada, Air Pollution Control Directorate, National Inventory of Natural Sources and Emissions of Sulphur Compounds, Report EPS-3-AP-79-2 (February 1980).

5. Environment Canada, Air Pollution Control Directorate, National Inventory of Natural Sources and Emissions of Nitrogen Compounds, Report EPS-3-AP-80-4 (January 1981).

E PROJECTED EMISSIONS

This chapter provides estimates of projected emissions of SO_2 and NO_x for all sectors of concern in both the United States and Canada. Several models and scenarios are used to depict a range of projected emissions to the year 1980 and/or 2000.

E.1 IN THE UNITED STATES

Emissions have been projected by the Department of Energy for all sectors using the Strategic Environmental Assessment System (SEAS) model, and by the Environmental Protection Agency using several models. Projected emissions are presented in Tables E.1.1 through E.1.4.

The results from these models differ somewhat, as would be expected, but agree on the basic conclusion that electric utilities are, and will remain, the dominant man-made emitters of both sulphur dioxide and nitrogen oxides in the United States.

Because of their impact on national emissions, more sophisticated models were used to evaluate the impact of various hypothetical emission regulations for power plants.

(1) Description of Methodologies

Utility emissions were projected using two models: the Utility Simulation Model (USM), developed and operated by Teknekron Research, Incorporated (TRI), and the Coal and Electric Utilities Model (CEUM) developed and run by ICF Incorporated. Both models are capable of projecting future energy use, by fuel type, for the electric utility industry, given a baseline energy scenario. The models also calculate the cost of emission controls, emissions and relative cost effectiveness of control, on a dollar per tonne of collected pollutant basis.

The two models differ in basic design. CEUM uses representative units which behave according to model constraints and optional economics. USM begins with a data base including all existing power plant units in the continental U.S., and scales up to future demand by simulating plant additions. Both models can simulate the choice of different coal supply sources and concomitant transportation paths.

Each model was run to establish a benchmark "base case." This benchmark is compliance with current air pollution regulations in State Implementation Plans (SIPS) and, for newer plants, compliance with New Source Performance Standards (NSPS). The analyses were made of various feasible pollution control scenarios. Except for three common regulatory scenarios, different scenarios were assessed by each model, depending on the strengths of the particular models. Analysis to date has focused on sulfur dioxide emissions, although nitrogen oxide emissions will also be evaluated.

TABLE E.1.1 NATIONAL SO_x PROJECTED EMISSIONS USING SEAS MODEL (10^6 tons)

	1975	1985	1990
Utility Boiler	20.2	19.1	19.8
Industrial Boiler/Process Heat	3.6	5.4	5.5
Non-Ferrous Smelters	2.1	0.8	0.8
Other Energy	1.6	1.5	0.4
Transportation	0.6	0.9	1.1
TOTAL	28.1	27.7	27.6

Source: SEAS - NEP III Scenario, high energy supply.

TABLE E.1.2 NATIONAL NO_x PROJECTED EMISSIONS USING SEAS MODEL (10^6 tons)

	1975	1985	1990
Utility Boiler	6.3	7.8	8.6
Industrial Boiler/Process Heat	2.5	4.9	3.9
Non-Ferrous Smelters	-	-	-
Other Energy	1.0	1.6	1.7
Transportation	8.5	7.8	6.5
TOTAL	18.3	22.1	20.7

Source: SEAS - NEP III Scenario, high energy supply.

TABLE E.1.3 NATIONAL SO_x PROJECTED EMISSIONS USING COMBINED MODELS (10^6 tons)

	1980	1985	1990	1995	2000
Utility Boiler	19.5	17.9	18.6	19.0	18.5
Industrial Boiler/Process Heat	5.9	5.7	6.8	8.6	10.3
Non-Ferrous Smelters	2.0	0.77	0.60	0.56	0.52
Residential Commercial	1.4	1.4	1.2	0.9	0.6
Transportation	0.9	0.9	0.9	0.9	0.9
TOTAL	29.7	26.7	28.1	30.0	30.8

Source: These emission estimates based on 1980 trends but projected with % change of models (utility - TRI; industrial ICF; RES/COM - SEAS; Transportation Ann Arbor), NF smelters from an actual unit-by-unit survey.

TABLE E.1.4 NATIONAL NO_x PROJECTED EMISSIONS USING COMBINED MODELS (10^6 tons)

	1980	1985	1990	1995	2000
Utility Boiler	6.2	6.8	7.6	8.4	9.2
Industrial Boiler/Process Heat	6.2	6.5	6.9	7.6	8.4
Non-Ferrous Smelters	0.0	0.0	0.0	0.0	0.0
Residential Commercial	0.9	0.9	0.8	0.8	0.7
Transportation	9.0	8.3	8.6	9.4	10.2
TOTAL	22.3	22.5	23.9	26.2	28.5

Source: These emission estimates based on 1980 trends but projected with % change of models (utility - TRI; industrial ICF; RES/COM - SEAS; Transportation Ann Arbor), NF smelters from an actual unit-by-unit survey.

The regulatory scenarios modeled by ICF and TRI are presented in Tables E.1.5 and E.1.6. Baseline energy scenarios are presented in Table E.1.7. Other key assumptions are identified in Table E.1.8.

TABLE E.1.5 ICF SCENARIO RUNS

- Run 1 -- Base Case,
- Run 2 -- 10 percent rollback of emissions in the 31-state Acid Rain region,
- Run 3 -- 30 percent rollback of emissions in the 31-state Acid Rain region,
- Run 4 -- 10 percent rollback of emissions in each of the 45 CEUM demand regions,
- Run 5 -- 30 percent rollback of emissions in each of the 45 CEUM demand regions,
- Run 6 -- 4.0 lb $SO_2/10^6$ Btu emission cap, and
- Run 7 -- 2.0 lb $SO_2/10^6$ Btu emission cap.

Results from examination of seventeen hypothetical regulatory scenarios are presented in Tables E.1.9-E.1.13. Tables E.1.9 and E.1.10 present results on scenarios examined by both models. Tables E.1.11 through E.1.13 are specific to each model. These results should be considered preliminary in nature. They have not undergone intensive review by the sponsoring agencies.

The results indicate that it is feasible to obtain reductions in power plant SO_2 emissions in excess of 30% without increasing the nationwide average price of electricity to consumers by more than about 2%. Significant reductions can be obtained for about $200-300 per ton of SO_2 removed.

The USM model results indicate that the 30% reduction could be achieved with an expenditure of less than one billion dollars for capital (compare Table E.1.13 and Figure E.1.2 for scenarios S50, SC2 and RMR). The CEUM model forecasts capital costs of three to seven billion dollars by 1990 for the same reduction in emissions, depending on how efficiently the reduction is obtained (see Tables E.1.9 and E.1.10). The most capital-intensive approach analyzed, the 2 lb cap, would cost about $10 billion by 1990, according to CEUM.

The total use of coal does not appear to be affected by those control strategies considered. However, some control strategies do appear to reduce the demand

TABLE E.1.6 SCENARIO DESCRIPTIONS FOR TRI ANALYSIS

Scenario	Regulatory Strategy	Units Affected
BNC	1979 status quo	all SIP units continue to emit SO_2 at the rate existing in 1979; units with planned or operating scrubbers are allowed to do so
BSC	SIP compliance	all SIP units are required to meet promulgated regulations by 1985; compliance is determined by annual averaging of specified regulation
BSS	Strict SIP compliance	all SIP units are required to meet promulgated regulations by 1985; compliance is determined by state specified periods of averaging time
SC4	4 lb SO_2/mBtu Cap	all SIP units are required to meet promulgated regulations by 1985; no SIP limit is allowed to exceed 4 lb per million Btu
SC2	2 lb SO_2/mBtu Cap	all SIP units are required to meet promulgated regulations by 1985; no SIP limit is allowed to exceed 2 lb per million Btu
S50	50% SIP Rollback	all SIP units greater than or equal to 100 megawatts, on-line beginning in 1950, are required to comply with their promulgated SIP limit reduced by 50 percent (none to fall below 0.8 lb/mBtu); all SIP units less than 100 megawatts are required to comply with SIP limit
RMR	50% SIP Rollback and 50% minimum removal	all SIP units greater than or equal to 100 megawatts, on-line beginning in 1950, are required to comply with their promulgated SIP limit reduced by 50 percent (none to fall below 0.8 lb/mBtu), and remove a minimum of 50 percent of the potential SO_2/mbtu in the coal entering utility boiler; all SIP units less than 100 megawatts are required to comply with SIP limit; all oil-fired units meeting the first criterion meet SIP limits reduced by 50 percent
R35	35 year lifetimes for all fossil-fuel-fired units	all fossil-fuel-fired units (oil, gas, coal) are retired at 35 years of age; baseline SIP compliance required

TABLE E.1.6 SCENARIO DESCRIPTIONS FOR TRI ANALYSIS (Cont'd)

Scenario	Regulatory Strategy	Units Affected
LED	Least Emissions Dispatch	all units are dispatched according to SO_2 emission rate classes rather than least operating cost; baseline SIP compliance required
UCW	Universal Coal Washing	all SIP units are required baseline SIP compliance; if the unit is complying as of 1979 status quo - it is still required to use physical coal cleaning (level 1); if not complying as of 1979 - the unit is allowed all compliance options, including fuel-switching, not including scrubbing of raw coal or blending of raw coal; in all cases, in order for cleaned coal to be chosen -it must contain at least a 10-percent reduction in potential SO_2 emissions relative to raw coal
CWF	Coal Washing Floors	all SIP units are required baseline SIP compliance; all coal above mine-state specified SO_2/mBtu floors is required to be cleaned to physical coal cleaning level 1; coal use and compliance options are the same as in the Universal Coal Washing scenario, with the omission of the constraint requiring cleaned coal to be 10 percent lower than raw coal in potential SO_2 emissions
S30	30% SIP Rollback (AIRTEST model only)	all SIP units greater than or equal to 100 megawatts, on-line beginning in 1950, are required to comply with their promulgated SIP limit reduced by 30 percent (none to fall below 0.8 lb/mBtu); all SIP units less than 100 megawatts are required to comply with SIP
RSC	1979 NSPS compliance for SIP units (AIRTEST model only)	all SIP units greater than or equal to 100 megawatts, on-line beginning in 1950, are required to comply with the 1979 New Source Performance Standards; all SIP units less than 100 megawatts are required to comply with SIP limit
NX7	0.7 lb/mBtu NO_x limit (AIRTEST model only)	all SIP units are required SIP compliance and 0.7 lb/mBtu NO_x limit

TABLE E.1.7 ENERGY CONSUMPTION COMPARISON DOE/TRI/ICF/(QUADS)

	1985			1990			1995			2000	
Fuel	DOE	ICF	TRI	DOE	ICF	TRI	DOE	ICF	TRI	DOE	TRI
Oil	3.4	2.3	3.3	2.6	2.1	3.1	2.1	2.4	2.6	1.7	2.0
Gas	2.8	3.4	2.4	3.1	3.9	1.9	2.6	3.2	1.6	2.1	1.1
Total Oil & Gas	6.2	5.7	5.7	5.7	5.9	5.0	4.7	5.6	4.2	3.8	3.1
Coal	14.9	15.0	14.7	17.9	17.2	18.1	19.8	21.0	21.7	23.4	25.9
Nuclear	5.0	4.6	4.9	7.4	7.0	7.0	8.3	8.9	8.4	8.8	8.9
TOTAL	26.1	25.3	25.3	31.0	30.1	30.1	32.8	35.5	34.3	36.0	37.9

TABLE E.1.8 KEY ASSUMPTIONS

- Energy projections provided by DOE (attached)
- Utility lifetimes
  - ICF - 45 Years for All
  - TRI - 45 Years for Coal
    40 Years for Gas
    35 Years for Oil, Nuclear
- UOB plants converted to coal - must comply with existing coal SIP's
- ICF constrained coal use by $2000/kW penalty for all new construction
- Nuclear capacity factor 65% - TRI; 70% - ICF
- SIP and strategy compliance by 1985
- Annual average SIP's (defined by EPA)
- Credit for
  - Overcomplying with SIP's
  - Sulfur Retention in Ash
- Pollution control costs defined by EPA (with input from DOE)

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for relatively high-sulfur coals in northern Appalachia and the midwest in comparison to the base case. (See Tables E.1.9, E.1.10, and E.1.12).

Other model results, not reflected in these national summaries, include:

- Most power plant emissions through 1995 come from existing power plants. More stringent new source requirements will not significantly reduce SO_2 emissions.
- Additional SO_2 control in the 31 eastern states is about an order of magnitude more cost effective than controlling the western states. However, western coal is of such high quality, some strategies (e.g., 4 lb cap) did not affect the west at all.
- Increasing the optimization area reduces nation control costs. That is, a 30% reduction in the eastern states is about one-third cheaper if state boundaries are ignored and the least expensive strategy is pursued, instead of obtaining the same overall reduction by reducing emissions in each state by 30%.
- Finally, it should be noted that NO_x control strategies and combined NO_x/SO_2 strategies will also be assessed. One strategy in particular, use of Limestone

TABLE E.1.9 1990 FORECASTS FOR COMMON SCENARIOS

	RUN DESCRIPTION					
	BASE CASE		4 lb CAP		2 lbs CAP	
	UMS	CEUM	USM	CEUM	USM	CEUM
SO_2 Emissions (10^6 tons/yr)	18.6	18.9	16.7	16.2	13.0	11.7
Annualized Costs ($1980 X 10^9/yr)	159.6	110.6	159.9	111.3	160.8	113.0
% Change over Base Case	-	-	+0.2	+0.6	+0.8	+0.3
Cost Effectiveness ($/ton removed)	-	-	160.0	254.0	240.0	342.0
Electricity Rate Increase (%)	-	-	0.2	0.4	0.8	1.3
Wet FGD (GW)	155.0*	53.0	159.0*	67.0	214.0*	78.0
Dry FGD (GW)		28.0		27.0		48.0
Capacity Penalty (GW)	1.8	2.1	1.8	2.2	2.0	2.5
**Coal Production Changes (10^6 tons)						
Northern Appalachia	135.0	209.0	-16.0	+1.0	-54.0	-21.0
Central and Southern Appalachia	151.0	340.0	+21.0	+2.0	+44.0	+33.0
Midwest	114.0	174.0	-8.0	-17.0	-19.0	-37.0
Western Northern Great Plains	163.0	260.0	-1.0	+4.0	-7.0	-3.0
Rockies and Southwest	73.0	152.0	+5.0	+11.0	+35.0	+18.0
Coal Use (10^{15} Btu/yr)	18	17	18	17	18	17
Total Capital Costs ($1980 X 10^9)	NA	308	NA	310	NA	318

* Both wet and dry scrubbing are included.

** Coal production change estimates for the USM model are for 1985. The base case production estimate for CEUM includes all coal produced including that used by non-utility sources and that exported whereas USM estimates only apply to production required to meet utility steam-coal requirements. Thus the absolute numbers for the base case are not directly comparable.

TABLE E.1.10 1990 FORECASTS FOR CEUM RUNS

	RUN NUMBER						
	No. 1 Base	No. 2 10% ARM	No. 3 30% ARM	No. 4 10% Each	No. 5 30% Each	No. 6 4 Pound	No. 7 2 Pound
SO_2 Emissions (10^6 tons/yr)	18.9	17.2	13.8	17.0	13.3	16.2	11.7
Annualized Costs ($1980 X 10^9/yr)	110.6	110.8	111.5	111.8	114.1	111.3	113.0
% Change over Base Case	-	0.2%	+0.8%	+1.0	+32.0	+0.6	+0.3
Cost Effectiveness ($/ton removed)	-	115.0	175.0	628.0	618.0	245.0	342.0
Electricity Rate Increase (%)	-	0.1	0.5	0.6	1.9	0.4	1.3
Wet FGD (GW)	53.0	54.0	61.0	54.0	63.0	67.0	78.0
Dry FGD (GW)	28.0	29.0	30.0	31.0	52.0	28.0	48.0
Capacity Penalty (GW)	2.1	2.1	2.3	2.1	2.4	2.2	2.5
*Coal Production Changes (10^6 tons)							
Northern Appalachia	209.0	-2.0	-20.0	-7.0	-17.0	+1.0	-21.0
Central and Southern Appalachia	340.0	+8.0	+27.0	+6.0	+22.0	+2.0	+33.0
Midwest	174.0	-15.0	-25.0	-10.0	-27.0	-17.0	-37.0
Western Northern Great Plains	260.0	-3.0	-1.0	-4.0	-5.0	+4.0	-3.0
Rockies and Southwest	152.0	+9.0	+17.0	+9.0	+24.0	+11.0	+18.0
Rest of West	116.0	+1.0	+2.0	0.0	-2.0	1.0	+2.0
Coal Use (10^{15} Btu/yr)	17.0	17.0	17.0	17.0	17.0	17.0	17.0
Total Capital Costs ($1980 X 10^9)	308	319	311	309	316	310	318

* Coal production change estimates for the USM model are for 1985. The base case production estimate for CEUM includes all coal produced including that used by non-utility sources and that exported whereas USM estimates only apply to production required to meet utility steam-coal requirements. Thus the absolute numbers for the base case are not directly comparable.

TABLE E.1.11 1990 FORECASTS FOR USM/AIRTEST RUNS

	RUN IDENTIFICATION										
	BNC	BSC	BSS	SC4	SC2	S50	PMR	R35	LED	UCW	CFW
SO_2 Emissions (10^6 tons/yr)	19.9	18.6	16.5	16.7	13.0	14.1	12.7	17.7	16.1	17.3	16.2
Annualized Costs ($1980 X 10^9/yr)	159.0	159.6	159.9	159.9	160.8	160.7	161.2	163.9	160.4	159.8	NA
% Change over Base Case	-0.4	-	+0.2	+0.2	+0.8	+0.7	+1.0	+2.7	0.5	0.1	-
Cost Effectiveness ($/ton removed)	-	-	140.0	160.0	210.0	240.0	270.0	480.0	320.0	150.0	-
Electricity Rate Increase (%)	-0.2	0.0	0.2	0.2	1.1	0.9	1.3	0.7	0.6	0.2	-
FGD - Wet & Dry (GW)	135.0	155.0	169.0	159.0	214.0	220.0	270.0	174.0	155.0	151.0	153.0
Capacity Penalty (GW)	1.7	1.8	1.8	1.8	2.0	2.0	2.2	2.2	1.8	1.8	1.8
Coal Use (10^{15} Btu/yr)	18	18	18	18	18	18	18	18	18	18	18

TABLE E.1.12 USM COAL PRODUCTION ESTIMATES (10^6 tons)

			SCENARIO RUNS FOR 1985									
	1980	BASE	BNC	BSS	SC4	SC2	S50	RMR	R35	LED	UCW	CWF
Northern Appalachia	134	135	+7	-24	-16	-54	-42	-43	0	-2	-5	-4
Central and Southern Appalachia	117	151	-10	+28	+21	+44	+42	+47	+1	+7	-6	-5
Midwest	116	114	+9	-5	-8	-19	-12	-6	0	-11	+4	0
Western Northern Great Plains	123	163	+4	-3	-1	-7	-9	-15	0	0	-1	-3
Rockies and Southwest	45	73	-8	+6	+5	+35	+18	+16	0	+11	0	0

TABLE E.1.13 NATIONAL ANNUAL UTILITY COSTS: 1985, 1990, 1995, 2000 ($ Billion - 1980)

	BNC	BSC	BSS	SC4	SC2	S50	RMR	R35	LED	UCW
1985:										
Fuel	62.0	62.2	62.2	62.3	62.5	62.3	62.0	62.2	62.8	62.4
O&M	19.4	19.5	19.6	19.6	19.9	20.0	20.5	19.5	19.5	19.4
Capital	49.7	49.7	49.9	49.8	50.3	50.2	50.5	50.6	49.9	49.7
Total	131.1	131.3	131.6	131.6	132.7	132.5	133.0	132.2	132.1	134.5
1990:										
Fuel	73.5	73.7	73.7	73.8	74.2	73.9	73.6	73.1	74.4	74.0
O&M	24.9	25.1	25.2	25.2	25.5	25.6	26.1	25.4	25.2	25.0
Capital	60.5	60.8	60.9	60.9	61.3	61.3	61.5	65.5	60.8	60.8
Total	159.0	159.6	159.9	159.9	160.8	160.7	161.2	163.9	160.4	159.8
1995:										
Fuel	82.5	82.6	82.6	82.7	83.1	82.8	82.6	80.6	83.5	82.9
O&M	30.2	30.3	30.5	30.4	30.8	30.8	31.3	39.9	30.5	30.3
Capital	66.2	66.4	66.5	66.4	66.7	66.6	66.7	73.1	66.4	66.4
Total	178.9	179.3	179.6	179.6	180.6	180.3	180.7	184.5	180.4	179.6
2000:										
Fuel	88.9	89.0	89.1	89.2	89.5	80.2	80.1	86.5	90.3	89.4
O&M	35.3	35.4	35.5	35.4	35.8	35.8	36.3	36.0	35.7	35.3
Capital	76.2	76.1	76.2	76.2	76.2	76.2	76.2	82.4	76.1	76.2
Total	200.3	200.5	200.8	200.8	201.5	201.3	201.6	204.8	202.1	200.8

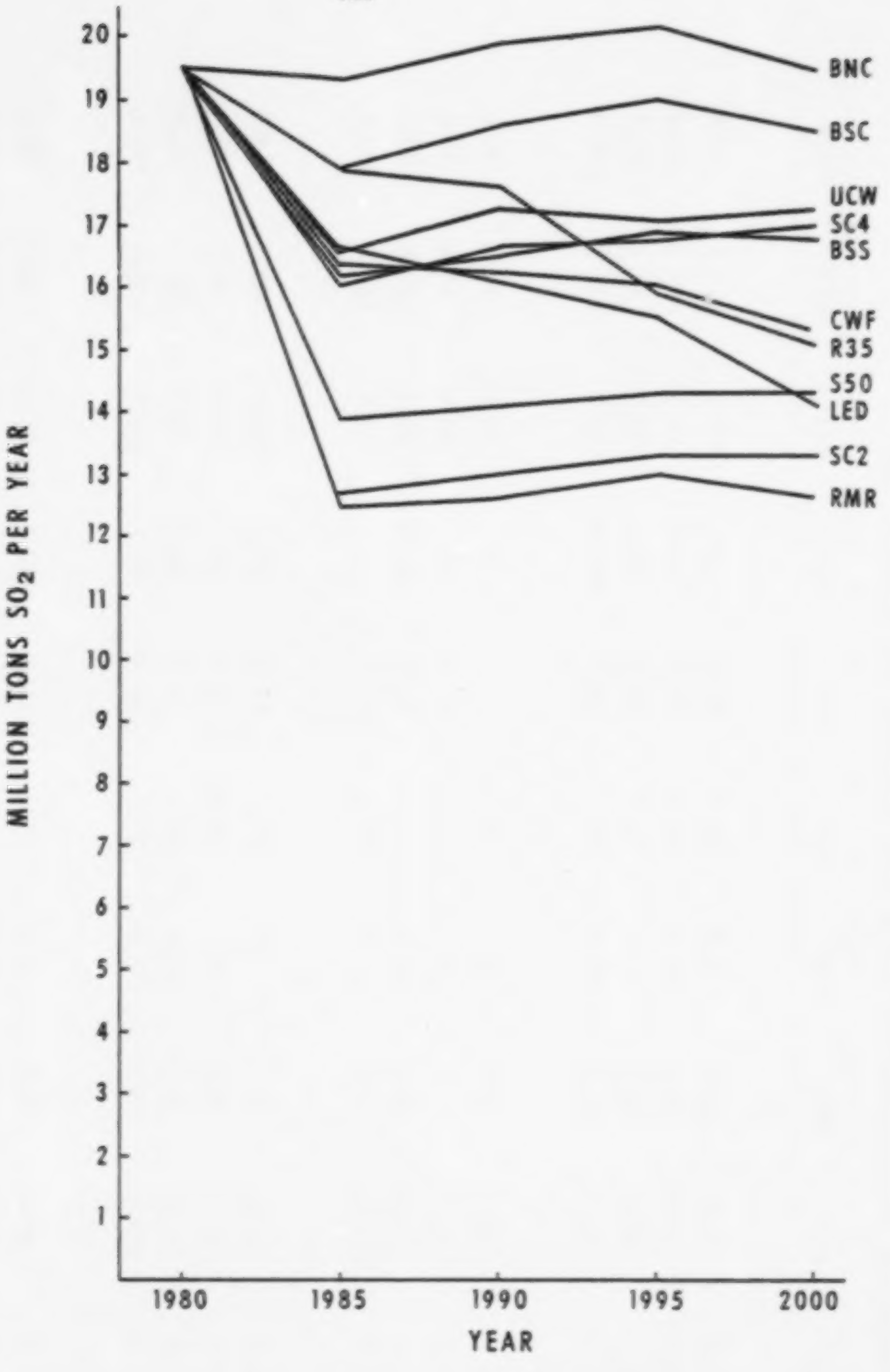
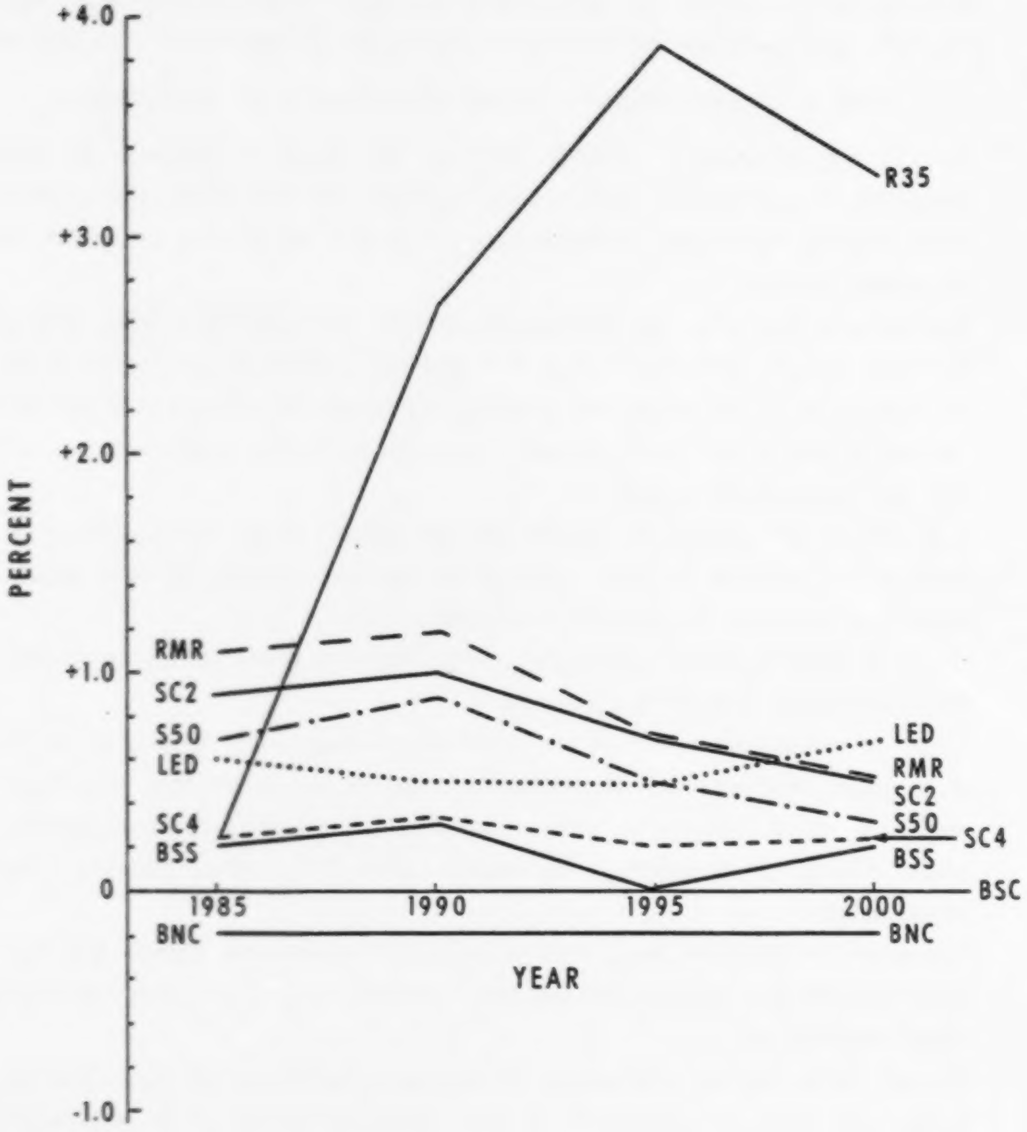


FIGURE E.1.1 NATIONAL UTILITY SULFUR DIOXIDE EMISSIONS 1980-2000 AS PROJECTED BY USM (MILLION TONS PER YEAR)



FIGUREE.1.2 PERCENTAGE CHANGE FROM BASE CASE NATIONAL INVESTOR ELECTRICITY PRICES AS PROJECTED BY USM

Injection with Modified Burners (LIMB) might yield reduction of both NO_x and SO_2 at costs well below those for conventional scrubbers. However, this technology is in the developmental stage and would not be available for installation until after 1985.

A few caveats should accompany any assessment of the model results.

- Results are preliminary findings and can be viewed confidently as correctly indicative of qualitative trends. Their quantitative accuracies have considerable error margins, due largely to inexactness of many of the models input data, such as the energy scenario.
- Cost outputs should be used with great caution. They assume a utility will seek to minimize overall costs and it is clear that some utilities do not choose to do this, but instead minimize capital expenditures. For example, a utility may choose to use low-sulfur coal to meet a requirement, even though capital investment in a scrubber may be less expensive overall.
- Costs to break existing contracts are not reflected in this analysis. This is important because of the great reliance on cleaned or low-sulfur coal, which often requires a change in coal source for a utility.
- Costs for specific power plants are expected to vary markedly (up and down) from the typical costs modeled in this study.
- Artificial constraints on use of low-sulfur coal will increase the overall control cost of a given strategy because low-sulfur coal tends to be less expensive than scrubbing. Such constraints could be imposed to prevent loss of coal demand from areas having predominantly high-sulfur cost (e.g., the midwest, northern Appalachia).
- The costs for FGD are low. FGD costs in CEUM are only slightly low, but FGD costs in USM are significantly too low. Additional analyses with more accurate costs are underway.
- Certain costs may be overstated, for example, benefits from coal cleaning from lower O/M costs and transportation costs were not included. More generally the benefits from pollution control were not considered in the cost-effectiveness measures.

E.2 IN CANADA

E.2.1 PROJECTED EMISSIONS - THERMAL POWER

Canada's electrical generating capacity is expected to increase substantially by 1990, exceeding 1977 capacity by over 60 percent.(1) This expansion will be noticeable in all three major types of generation: hydroelectric, nuclear, and conventional thermal. Hydroelectric power will maintain its leading role in the utility sector, nuclear power will grow by a factor of three, and thermal generation will increase to a somewhat lesser degree.

Conventional steam electric capacity, which was 19 200 MW in 1978, may increase to 29 000 MW by the end of 1989.(1) All announced steam-unit additions by 1990 will be coal-fired. This added coal-burning capacity will cause annual coal consumption to increase by 127 percent, from 21 100 kilotonnes in 1977 to approximately 47 900 kilotonnes in 1989. The majority of the steam-unit additions are in the provinces of Alberta and British Columbia.

Table E.2.1 shows each province's percentage distribution of installed capacity by generation type for both 1977 and 1989. The type categories are standard: coal steam, oil steam, gas steam, nuclear, hydro, gas turbine, and internal combustion.

The 1989 distributions do not include the effects of any capacity penalties due to pollution control devices and therefore represent the distributions that would occur in the case involving no active pollution control. The changes in the distributions due to the imposition of pollution control penalties are not great.

In Table E.2.2, the generation mix by province is presented for the two years 1977 and 1989. Note that Nova Scotia, Saskatchewan, Alberta, and British Columbia substantially increase their share of generation from coal units. In

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(1) Statistics Canada, Electric Power Statistics, Vol. 1, Annual Electric Power Survey of Capability and Load - 1979-1983 Forecast, 57-204 Annual (Ottawa, Ont.: Manufacturing and Primary Industries Division, Energy and Minerals Section, September 1979); Department of Energy, Mines and Resources, Electric Power in Canada - 1979 (Canada: Electrical Section - Energy Policy Sector, 1980); "Canada -Still Planning for a Strong 1980," Electrical World 1980 Statistical Report, 5 March 1980.

TABLE E.2.1 COMPARISON OF GENERATING CAPACITY MIX, BY PROVINCE, 1977 and 1989 (PERCENT)

Province	Coal	Oil	Gas	Nuclear	Hydro	Turbine	Internal Combustion
P.E.I.							
1977	0.00	57.89	0.00	0.00	0.00	35.96	6.14
1989	0.00	57.89	0.00	0.00	0.00	35.96	6.14
Nfld.							
1977	0.00	4.54	0.00	0.00	92.01	2.48	0.96
1989	0.00	6.31	0.00	0.00	90.05	2.72	0.92
N.S.							
1977	22.70	51.37	0.00	0.00	11.14	14.73	0.07
1989	47.66	28.88	0.00	0.00	15.15	8.28	0.04
N.B.							
1977	6.22	60.63	0.00	0.00	31.81	1.11	0.24
1989	10.53	40.26	0.00	20.16	28.16	0.74	0.16
Que.							
1977	0.00	4.28	0.00	1.39	92.66	1.21	0.46
1989	0.00	1.60	0.00	1.69	85.03	11.39	0.29
Ont.							
1977	34.20	9.08	5.22	17.61	31.74	2.11	0.05
1989	29.80	6.06	3.49	37.82	21.38	1.41	0.03
Man.							
1977	12.67	0.00	0.00	0.00	86.00	0.76	0.57
1989	10.10	0.00	0.00	0.00	88.84	0.61	0.46
Sask.							
1977	45.28	0.00	19.15	0.00	28.04	7.43	0.10
1989	65.10	0.00	12.21	0.00	17.89	4.74	0.06
Alta.							
1977	58.69	0.00	19.71	0.00	16.10	4.69	0.81
1989	75.07	0.00	12.51	0.00	8.66	3.32	0.43
B.C.							
1977	0.00	0.00	12.64	0.00	82.13	4.02	1.20
1989	14.37	0.00	6.70	0.00	75.72	2.57	0.64
NATIONAL							
1977	18.82	7.84	5.30	6.37	58.40	2.78	0.47
1989	19.74	4.56	3.14	12.16	54.80	5.28	0.31

TABLE E.2.2 COMPARISON OF GENERATION MIX, BY PROVINCE 1977, and 1989 (PERCENT)

Province	Coal	Oil	Gas	Nuclear	Hydro	Turbine	Internal Combustion
P.E.I.							
1977	0.00	66.84	0.00	0.00	0.00	32.37	0.79
1989	0.00	43.36	0.00	0.00	0.00	48.97	7.66
Nfld.							
1977	0.00	0.67	0.00	0.00	99.19	0.07	0.07
1989	0.00	0.82	0.00	0.00	99.05	0.07	0.06
N.S.							
1977	10.40	58.64	0.00	0.00	19.14	11.81	0.01
1989	49.48	8.51	0.00	0.00	33.47	8.54	0.01
N.B.							
1977	7.56	33.48	0.00	0.00	57.99	0.94	0.03
1989	10.04	10.97	0.00	21.98	56.94	0.04	0.02
Que.							
1977	0.00	0.00	0.00	0.37	99.55	0.04	0.04
1989	0.00	0.00	0.00	0.49	99.05	0.44	0.03
Ont.							
1977	18.90	0.98	0.23	28.47	51.33	0.09	0.01
1989	12.19	0.62	0.14	54.18	32.80	0.06	0.00
Man.							
1977	5.50	0.00	0.00	0.00	94.40	0.03	0.06
1989	3.41	0.00	0.00	0.00	96.53	0.02	0.04
Sask.							
1977	55.72	0.00	0.79	0.00	43.17	0.30	0.01
1989	71.05	0.00	4.32	0.00	24.40	0.17	0.06
Alta.							
1977	61.51	0.00	11.07	0.00	27.12	0.21	0.09
1989	81.94	0.00	5.82	0.00	12.08	0.12	0.04
B.C.							
1977	0.00	0.00	0.51	0.00	99.21	0.16	0.12
1989	7.28	0.00	0.23	0.00	92.35	0.09	0.05

New Brunswick and Ontario, the nuclear share of generation rises considerably. In Newfoundland, Quebec, Manitoba, and British Columbia, hydro generation maintains its dominant role, accounting for well over 90 percent of generation in each of these provinces in both 1977 and 1989. Because of the expected rise in the price of gas and oil, the utilization of steam units using these fuels may fall in some provinces.

Emissions from Canadian thermal power plants can be viewed as originating in two major geographic subdivisions: the east (all provinces east of and including Ontario); and the west (all provinces west of and including the province of Manitoba). The eastern provinces have historically burned high-sulphur coals. Nova Scotia and New Brunswick have burned locally mined coals, while Ontario has burned high-sulphur coals from U.S. Appalachian mines in West Virginia and Pennsylvania. Some blending of these coals with low-sulfur sub-bituminous western Canadian coals is carried out in Ontario. Power plants in northwestern Ontario burn low-sulphur western coals. Except for British Columbia, the western provinces (predominantly Alberta) will probably continue their current practices of burning low-sulphur sub-bituminous coals and lignites mined within the region. British Columbia will burn lignites.

Present Emissions

With the exception of particulate matter, there are no controls applied to emissions from Canadian thermal power stations, other than those which occur fortuitously, i.e., some SO_2 is retained when certain western coal and lignite are burned, if the fuel ash contains enough calcium or sodium compounds to bind part of the oxidized sulphur during combustion. Similarly, some boilers utilize flue gas recirculation as superheat control, which has a beneficial effect on NO_x suppression.

Thus the emissions of SO_2 and particulate pollutants are ascertained by simple calculation for each unit in provincial utility systems, given the fuel tonnage fired, and its ash and sulphur content. The estimates for NO_x are less realistic, being made by the application of a factor to the tonnage of fuel fired to any given boiler.

The historical data show that nationally in 1976:

SO_2 emissions were some 553 000 tonnes
NO_x emissions were about 185 000 tonnes
Particulate emissions were about 168 000 tonnes

Feasible Reductions

It needs to be accepted that it is not feasible to reduce the present emissions from all emitters, since many units are old, or under-utilized, or lack the space to install control equipment, or have no hope of obtaining alternative fuels.

Future emissions may increase from their present values for many existing units, because they will be utilized to a greater degree, or they could be using fuel of greater polluting potential. The overall national thermal generating capacity is also increasing, and the new capacity will fire solid fuel exclusively. In addition, some eastern oil-fired stations are very likely to be converted to coal, possibly producing greater pollution than existed prior to conversion.

To calculate the projected emissions, it has been necessary to make assumptions for capacity growth and generation growth in all provinces for all types of generation. Further assumptions have had to be made on the probable degrees of control of the various emissions that will be politically acceptable, and technically practicable for different fuels. Most important, it has been assumed that new stations will be controlled wherever built, but that existing units will only be controlled where they are either large in themselves, or form part of large stations.

Table E.2.3 shows what is regarded as technologically feasible.

TABLE E.2.3 THERMAL POWER - PROJECTED SO_x AND NO_x EMISSIONS

	Year	SO_x kilotonnes/yr	NO_x kilotonnes/yr
"Business as Usual"	1983	830	330
(No controls)	1985	940	373
	1990	1050	470
	1995	1160	520
	2000	1280	570
"Stringent" Controls (degree of stringency varies with fuel)	1990	350	335

E.2.2 PROJECTED EMISSIONS FROM COPPER-NICKEL SMELTER COMPLEXES

A report recently prepared by Environment Canada provides an insight into projected levels of SO_2 emissions from the Canadian copper/nickel smelting sector (1). The projections are based on various assumptions which are considered to be the most probable for future emissions. While based on expert analysis and current information, they could be considerably altered by several variables. Historically, strikes, recessions, market prices, shutdowns, etc., have all affected emission levels. Such variables are obviously too difficult to predict very far into the future.

The last decade has reflected the effects of environmental pressures being brought to bear on the non-ferrous smelting industry. Emissions from this sector have decreased almost continuously since 1970 and can be attributed to process improvements, production cutbacks, and the closure of a smelter. Throughout this period, the decrease in total SO_2 emissions was augmented by increased pyrrhotite rejection at the Inco (Thompson), Inco (Sudbury area) and Falconbridge (Sudbury area) smelters; furthermore, the expansion of the acid plants at Inco's iron ore recovery plant (IORP) (Sudbury area), the addition of acid plants at the Gaspé (Murdochville) and Falconbridge smelters, coupled with the plant modernization completed at Falconbridge, combined to reduce emissions even more. Overall, SO_2 emissions from Canadian copper/nickel smelters decreased from a level of 3.7 million tonnes in 1970 to 2.5 million tonnes in 1977, or about 32%, while at the same time nickel production decreased by about 16% and copper production increased by close to 5% (1).

The total emission levels for 1978 (1.7 million tonnes) and 1979 (1.6 million tonnes) were not indicative of what might have been expected on an annual basis because of a severe 8 1/2 month strike which spanned both years and which served to artificially reduce emissions at Inco's complex in the Sudbury area from approximately 1.14 million tonnes in 1977 to about 0.54 million tonnes in each of 1978 and 1979. However, under a new Ontario government regulation, Inco emissions at its Copper Cliff complex are restricted to approximately 0.87 million tonnes per year starting in 1980. This level has been chosen as the base level assumption to estimate future emissions.

Based on the historical pattern of emissions to date (1950-1980) (1), and on current economic conditions which indicate an impending recession, it is not appropriate to project production increases for the near future. Therefore, based on these facts and the following assumptions:

- a recovery to normal levels of emissions at the Gaspé smelter following the six-month strike in 1979,
- a recovery at Inco's Copper Cliff smelter to the maximum allowable emission level as established by the Ontario government.

the emission levels at each smelter in 1980 are estimated to be as indicated in Table E.2.4. This being the case, the total SO_2 emissions for this sector would be approximately 2.04 million tonnes in 1980. These estimates form the base figures for all subsequent projections.

TABLE E.2.4 SO_2 EMISSION ESTIMATES BY OPERATION, 1980

Operation	Million tonnes	Operation	Million tonnes
Noranda - Horne	0.54	Inco - Thompson	0.23
- Gaspé	0.07	- Copper Cliff	0.80
Falconbridge	0.15	- IORP	0.07
Hudson Bay Mining and Smelting	0.19		
		OVERALL TOTAL	2.04

Scenario I

The validity of this scenario is dependent upon the existence of a status quo with respect to production capacity, pollution control and technological innovation and implementation. In essence, this unlikely situation disregards the future short-term effects of recessions, booms, or labor problems, and the long-term effects of pressures from environmental quarters to improve the existing situation.

Assuming that emission levels will remain unchanged throughout this period provides a ceiling level for emissions. Therefore, it is projected that the worst case would be approximately 2.0 million tonnes of SO_2 emitted annually from this sector in the year 2000 (see Figure E.2.1).

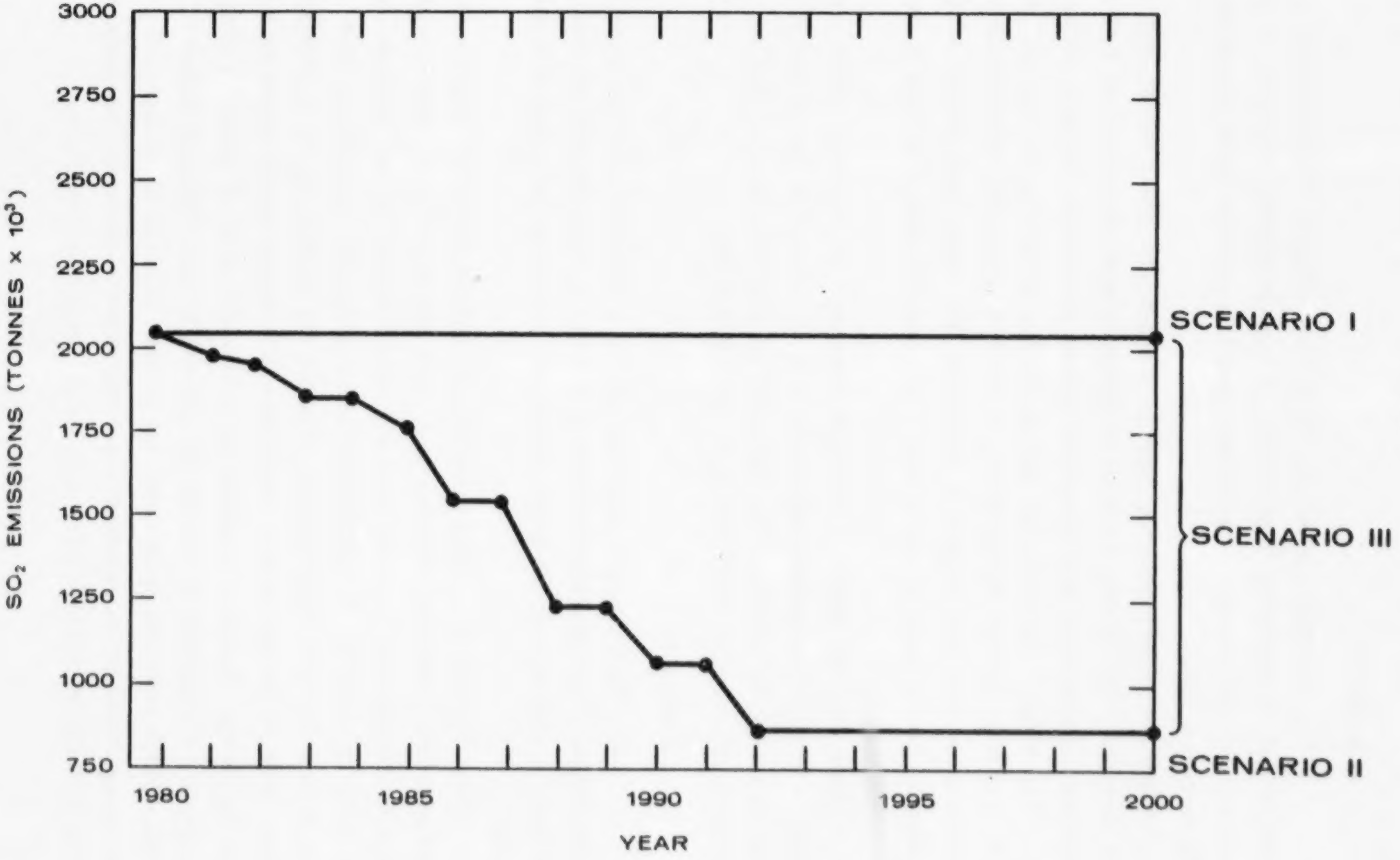

FIGURE E.2.1 SO_2 EMISSION PROJECTIONS, ANNUAL AVERAGES, 1980-2000

Scenario II

This scenario denotes the "best case" effect. It incorporates changes attributable to both technological improvements and environmental pressures. It assumes that short-term fluctuations due to recessions, booms, or labor problems will be averaged out on the long-term basis.

Based on expert analysis, several changes are predicted at the various smelters. Generally, the reductions can be attributed directly to conformity with control orders, process improvements, acid plant construction, and industrial hygiene pressures.

This scenario assumes that any production growth at the various smelters already in existence will be negligible or, if any occurs, process improvements would negate the consequences with respect to emissions. The Texas Gulf smelter is the only one for which capacity increases are forecast, and emissions have been duly increased to account for this.

Based on this analysis, five-year averages of emissions would decrease continuously from recent emission levels (1975-1979) of 2.17 million tonnes to 0.87 million tonnes by the end of the century. This represents an optimistic decrease of 60% without sacrificing production output (see Figure E.2.1 and Table E.2.5).

Scenario III

The third scenario does not provide a projection but rather suggests a figure somewhere within the range established by I and II. It is probably the most likely situation since it accounts for the large amount of uncertainty associated with the other projections.

While Scenario I assumes a pessimistic outlook that technological improvements and pollution control will not occur or at least will not be implemented, Scenario II assumes optimistically that improvements will be implemented at all smelters. Neither situation in highly probable. This is evident on examining past performance with respect to events that should have (theoretically at least) the highest degree of probability of occurrence. One would assume that compliance with control orders would have a high degree of certainty. However, economic situations and political pressures dictate not only changes to the magnitude of the figures involved, but also the time frames originally referenced. Since economic conditions are at best difficult to predict and political pressures, being dependent on expediency, are impossible to forecast, the probability of compliance with any specified time frame or specific emission level is low.

TABLE E.2.5 PROJECTED SO_2 EMISSIONS FROM COPPER-NICKEL SMELTER COMPLEXES, ANNUAL TOTALS AND 5-YEAR AVERAGES, 1980 - 2000

			Million tonnes			5-year averages
Year	1980	1981	1982	1983	1984	
Emission	2.04	1.99	1.96	1.86	1.86	1.94
Year	1985	1986	1987	1988	1989	
Emission	1.77	1.55	1.55	1.23	1.23	1.47
Year	1990	1991	1992	1993	1994	
Emission	1.08	1.08	0.87	0.87	0.87	0.95
Year	1995	1996	1997	1998	1999	
Emission	0.87	0.87	0.87	0.87	0.87	0.87

Thus, Scenario III assumes that some environmental control and technological improvements will occur in this sector, that production will be near or at capacity, and that the resulting emissions will be somewhere between 2.04 million tonnes and 0.87 million tonnes by the year 2000 (see Figure E.2.1).

It should be noted that under present conditions the environmental conscience of society has been aroused by an awareness of the dangers posed by acid rain. This arousal should, in all probability, ensure that some action will be taken to reduce emissions and hence Scenario III would tend to be in the more optimistic range.

As indicated in Figure E.2.2, it is anticipated that future emissions will be at least lower than in any of the previous periods examined. Should the most optimistic scenario prove valid, emissions by the year 2000 will have decreased approximately 75% from the peak levels recorded in the 60's. It is of note that levels have diminished close to 40% since the 1960's, so that a goodly portion of the reduction is still to come as indicated in Figure E.2.3.

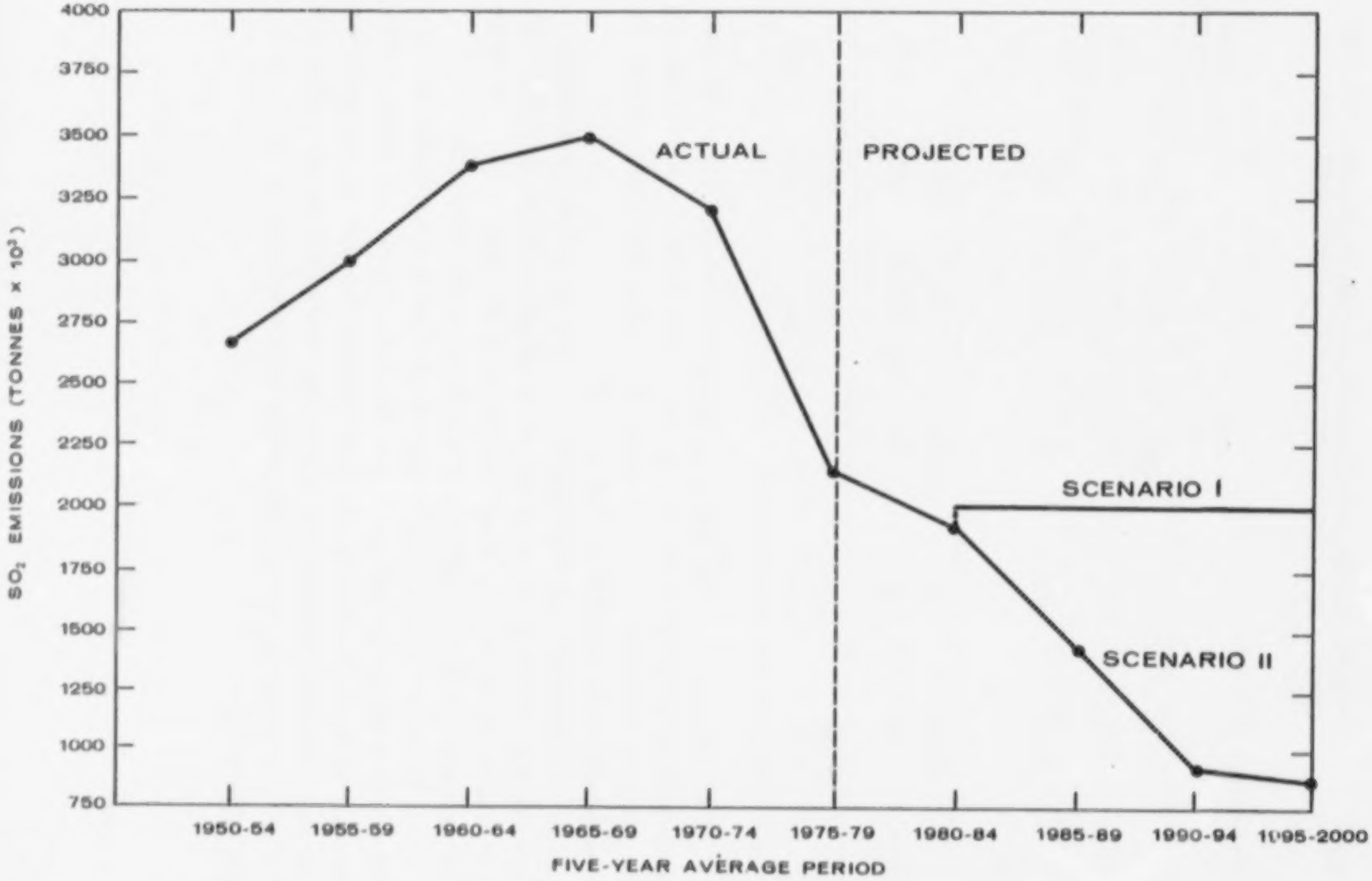

FIGURE E.2.2 SO$_2$ EMISSIONS FROM COPPER/NICKEL SMELTERS, ACTUAL AND PROJECTED, FIVE YEAR AVERAGES, 1950-2000

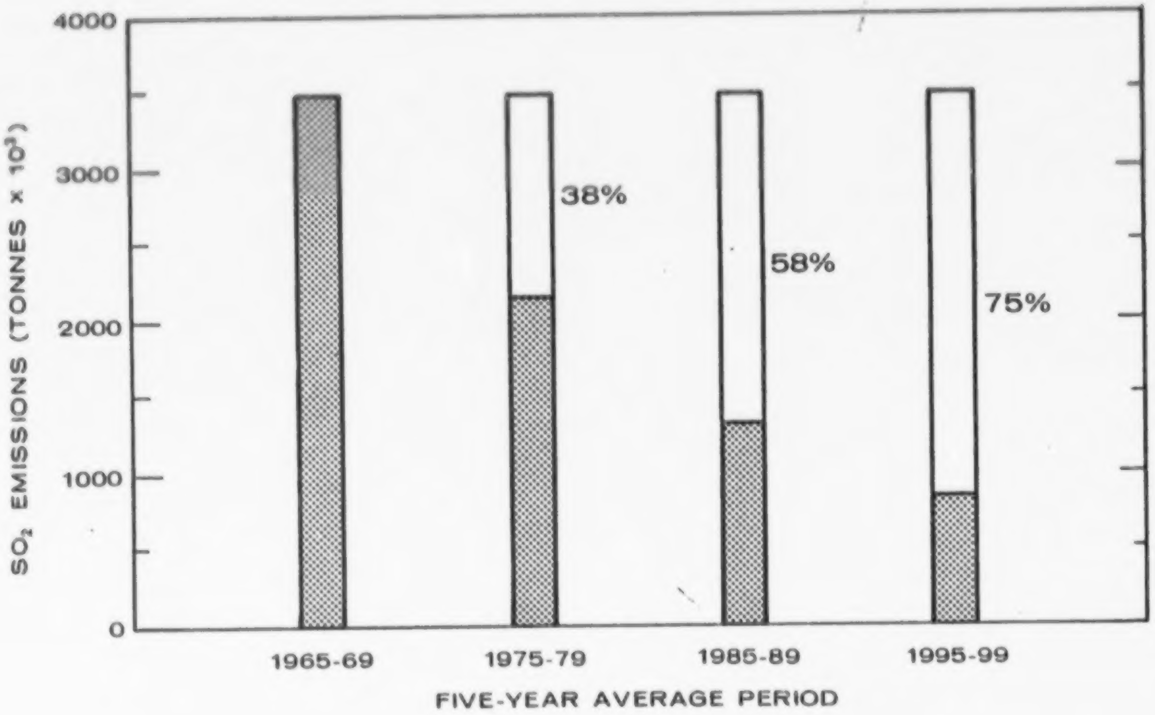

FIGURE E.2.3 PAST & PROJECTED SO_2 EMISSION DECREASES EXPRESSED AS A PERCENTAGE OF PEAK EMISSIONS IN 1965-69 (BASED ON SCENARIO II PROJECTION)

REFERENCES

1. Environment Canada, Air Pollution Control Directorate, Copper-Nickel Smelter Complexes in Canada, SO_2 Emissions (1950-2000), Report EPS 3-AP-80-5 (January 1981).

E.2.3 PROJECTED EMISSIONS - MOBILE SOURCES

Assuming normal growth rates in both numbers of cars (3%) and annual miles travelled by each car (3%) and in the absence of further control action at either the design or in-use levels, total NO_x emissions from motor vehicles can be projected to increase by 30 to 50% between 1980 and 1990.

If more stringent new vehicle emission standards become effective with the 1985 models, (which will result in catalytic control of NO_x with a corresponding reduction in the number of vehicles fitted with EGR valves) conceivably the actual emissions could be reduced (as a weighted average of the whole fleet) to the neighborhood of about 1.3 grams per mile in 1990. Total emissions would then be reduced about 20% from 1980 levels in spite of the assumed increases in car numbers and mobility.

In the absence of more stringent new vehicle standards it is conceivable that the tampering rate (with EGR valves - discussed elsewhere) might be beneficially affected by an inspection program on in-use vehicles. At the present time, however, we know of no effective test procedure let alone the actual quantitative benefits on NO_x emissions that might result from such an inspection program.

F. CONSTRAINTS ON AND BOUNDARIES OF ANALYSIS

This interim report addresses the initial concern, acid rain precursor emissions and sources only. The information presented in this report is predominantly for the eastern part of North America, i.e. roughly east of a north-south line running along the Manitoba-Saskatchewan border in Canada and the Mississippi River in the United States.

A detailed review of the following major sectors is included:

a) Thermal Power for SO_x and NO_x
b) Non-Ferrous Smelters for SO_x
c) Mobile Sources for NO_x

Other pollutants are mentioned in these sectors but have not been reviewed in detail.

Technology for the control of these pollutants is reviewed on a general basis but no site-specific assessments have been made.

Costs of control are also reviewed, in general terms, but no detailed site-specific assessments have been made.

A brief review of the following sectors is included:

a) Petroleum refining for SO_x and NO_x
b) Industrial, residential and commercial fuel combustion for SO_x and NO_x
c) Incinerators for SO_x and NO_x
d) Pulp and paper for SO_x and NO_x

No detailed review or assessment of control technology and costs has been made for these sectors.

SO_x and NO_x emissions are presented for all source sectors but no review of control technology or costs has been carried out, except as listed above.

Information on other pollutants, such as photochemical oxidants may be included in future reports if it is determined that they play a significant role in the transformation of SO_x and NO_x to acid-causing species.

G. RECOMMENDATIONS FOR FUTURE APPLIED R & D ACTIVITIES

A number of future applied R & D activities have been identified in this interim report for consideration. Future reports will address this activity in greater detail.

Recommendations

1. Development of improved lower energy consuming reliable FGD systems for thermal power, especially regenerative types.
2. Process/control technology development for the reduction of SO_x emissions from non-ferrous weak strength gas streams.
3. Research on methods, products and markets to reduce cost and energy consumption and improve environmental acceptability for the disposal of sulphur by-products.
4. Development of improved control technology for NO_x.
5. Development of systems/technology to accelerate the reduction of NO_x emissions from the existing transportation fleets.
6. An intensive R&D effort is required to characterize U.S. and Canadian coal resources in terms of their "cleanability" and to develop improved, less expensive methods of coal cleaning.
7. A long-term commitment to develop cleaner less expensive methods of coal combustion, such as coal gasification, should be made.
8. Improved estimates of current United States and Canadian emissions are needed. In particular, total U.S. emissions need refinement and disaggreation on a smaller geographic scale than is currently available. In addition, research is needed on seasonal variations in emissions and on primary emissions of sulfates.
9. An improved data base on NO_x emissions is required.
10. A long-term demonstration project on coal-limestone pellets using large stoker-fired boilers should be undertaken.
11. A near-term R&D project to demonstrate the emissions reductions achievable with and the economics of spray dryer FGD processes applied to high sulfur coals is required.

12. A long-term demonstration project on advanced low NO_x coal burners using pulverized coal should be funded.
13. Bench scale, pilot scale, and demonstration scale projects are needed to test limestone injection/multistage burner control technology.
14. Research is needed on advanced particulate control concepts that will lower the capital cost and operating costs associated with spray dryer SO_2 control.
15. SO_2 add-on control for smelters need to be studied, especially alternative acid plant configurations.
16. Innovative technologies for smelting operations need to be tested and demonstrated.

APPENDIX I

1 TERMS OF REFERENCE

The Terms of Reference contained in the Memorandum of Intent are:

This Work Group will provide support to the development of the "Control" element of an agreement. It will also prepare proposals for the "Applied Research and Development" element of an agreement.

In carrying out its work, the Subgroup will:

- identify control technologies, which are available presently or in the near future, and their associated costs;
- review available data bases in order to establish improved historical emission trends for defined source regions;
- determine current emission rates from defined source regions;
- project future emission rates from defined source regions for most probable economic growth and pollution control conditions;
- project future emission rates resulting from the implementation of proposed strategy packages, and associated costs of implementing the proposed strategy packages; and
- prepare proposals for the "Applied Research and Development" element of an agreement.

Work Plans, for this Work Group, have been submitted to Work Group 3A. The Work Plans will be modified as directed in Work Group 3A and to address problems identified in this Interim Report.

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APPENDIX 2

APPENDIX 2

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- Magnitude and Distribution of Eastern Canada SO_2 emissions - 1976 data base (map)
- Magnitude and Distribution of Eastern Canada NO_x emissions - 1976 data base (map)
- Listing of Eastern Canada SO_2 emissions on the 127 km x 127 km grid -1976/80 data base
- Listing of Eastern Canada NO_x emissions on the 127 km x 127 km grid - 1976/80 data base

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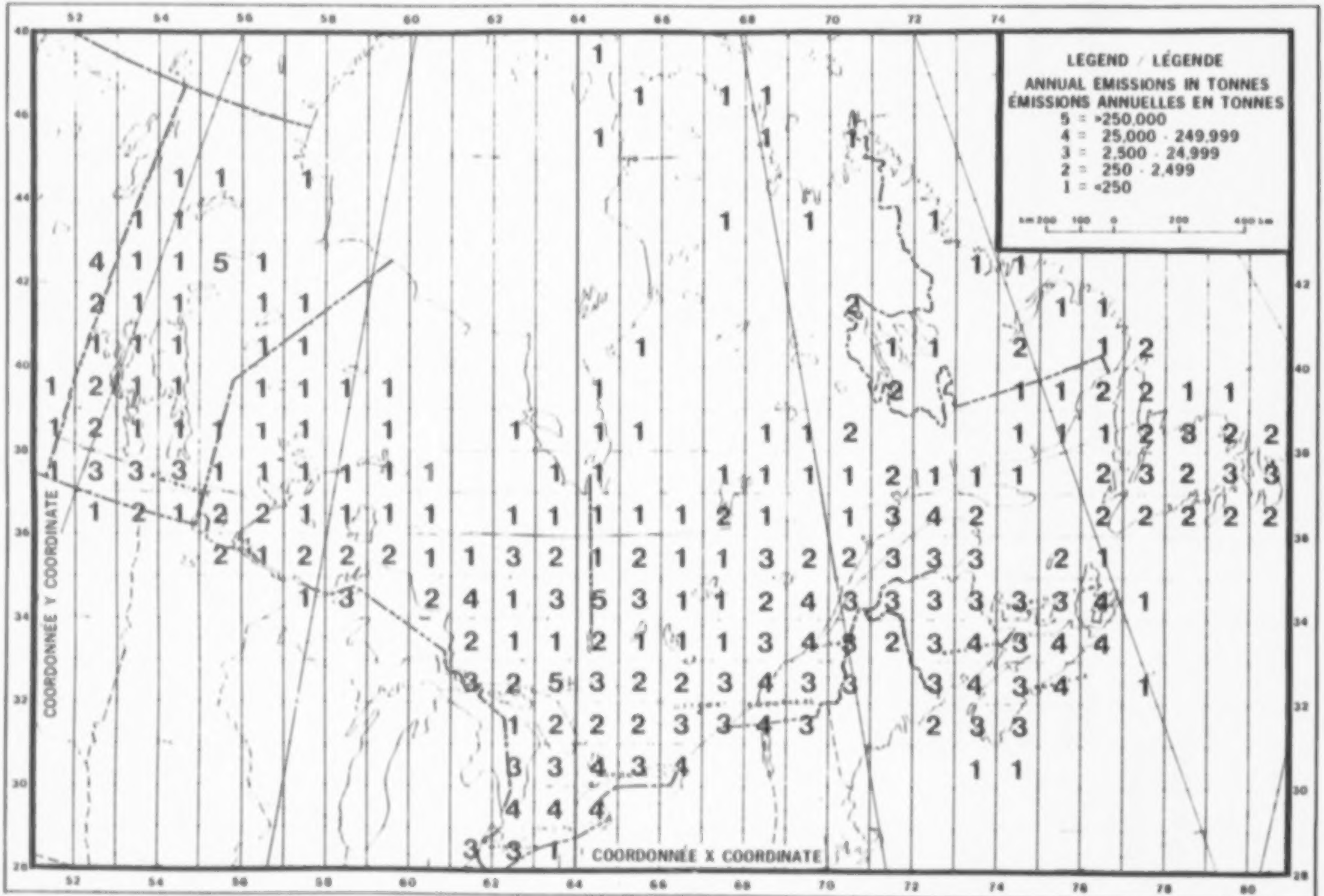
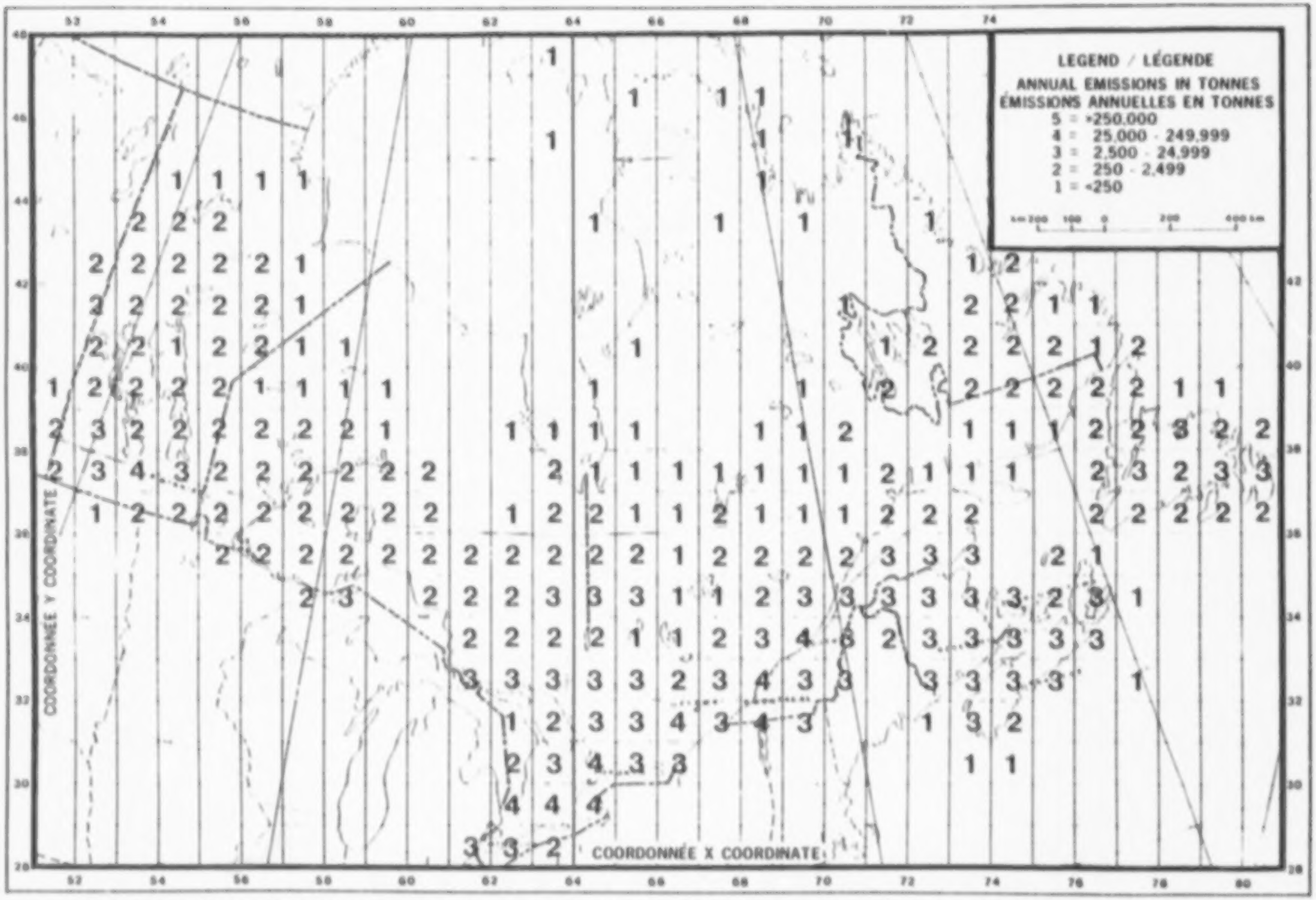


MAGNITUDE AND DISTRIBUTION OF EASTERN CANADA SO_2 EMISSIONS - 1976 DATA BASE ON 127 km × 127 km GRID

IMPORTANCE ET RÉPARTITION DES ÉMISSIONS DE SO_2 DANS L'EST DU CANADA - DONNÉES DE 1976 SUR GRILLE DE 127 km × 127 km



MAGNITUDE AND DISTRIBUTION OF EASTERN CANADA NO$_x$ (EXPRESSED AS NO$_2$) EMISSIONS · 1976 DATA BASE ON 127 km × 127 km GRID

IMPORTANCE ET RÉPARTITION DES ÉMISSIONS DE NO$_x$ (EXPRIMÉES EN NO$_2$) DANS L'EST DU CANADA · DONNÉES DE 1976 SUR GRILLE DE 127 km × 127 km

LISTING OF EASTERN CANADA SO_2 EMISSIONS ON THE 127 km x 127 km GRID

SO_x (as SO_2)

CANADIAN EMISSIONS DATA - 1976 THROUGH 1980 - ANNUAL ESTIMATES (PRELIMINARY) (IN TONNES)

(y coord.)							
47							
46							
45							
44				2	6		27
43		84	2				
42		152 226	59	16	334 019	48	
41		522	13	62		14	1
40		123	10	1		13	1
39	40	262	49	10		5	2
38	187	568	167	124	6	10	1
37	150	6 073	13 618	4 115	29	240	1
36		15	508	230	1 498	959	34
35					866	193	937
34							67
33							
32							
31							
30							
29							
28							
	51	52	53	54	55	56	57

(x coord.)

SO_x (as SO_2)

CANADIAN EMISSIONS DATA - 1976 THROUGH 1980 - ANNUAL ESTIMATES (PRELIMINARY) (IN TONNES)

(y coord.)							
47							1
46							
45							16
44							
43							
42							
41							
40							
39	3	2					105
38		17			1		90
37	9	2	1			45	83
36	24	8	18		1	1	1
35	583	581	233	227	5 296	398	133
34	6 897		557	182 264	13	4 873	540 695
33				1 190	33	36	1 140
32				2 765	1 411	1 006 890	6 060
31					79	250	1 299
30					19 593	4 721	35 656
29					200 212	182 485	210 026
28				7 415	4 115	213	
	58	59	60	61	62	63	64

(x coord.)

SO$_x$ (as SO$_2$)

CANADIAN EMISSIONS DATA - 1976 THROUGH 1980 - ANNUAL ESTIMATES (PRELIMINARY) (IN TONNES)

(y coord.)							
47							
46	16		5	2			
45				4		4	
44							
43			10		21		
42							
41						321	
40	26						55
39							1 507
38	1			1	1	289	
37			1	1	1	46	1 417
36	1	1	747	1		27	4 059
35	1 049	78	226	3 019	514	875	13 017
34	2 929	24	51	1 907	27 876	5 750	7 320
33	11	31	219	6 540	46 899	3 263	1 570
32	997	2 214	7 615	149 096	15 323	3 147	
31	723	20 565	17 442	143 356	8 932		
30	7 037	14 291					
29							
28							
	65	66	67	68	69	70	71

(x coord.)

SO_x (as SO_2)

CANADIAN EMISSIONS DATA - 1976 THROUGH 1980 - ANNUAL ESTIMATES (PRELIMINARY) (IN TONNES)

(y coord.)							
47							
46							
45							
44							
43	4						
42		10	3				
41				21	17		
40	108		493		50	260	55
39			1	1	281	299	94
38			1	61	185	826	4 935
37	81	241	44		5601	5 412	363
36	73 107	889			830	657	309
35	10 229	6 332		618	218		
34	16 963	12 322	12 603	6 387	34 578	107	
33	14 549	45 808	12 841	31 031	37 501		
32	5 539	95 557	18 882	68 080		0	
31	288	5 321	4 745				
30		88	134				
29							
28							
	72	73	74	75	76	77	78

(x coord.)

SO_x (as SO_2)

CANADIAN EMISSIONS DATA - 1976 THROUGH 1980 - ANNUAL ESTIMATES (PRELIMINARY) (IN TONNES)

(y coord.)		
47		
46		
45		
44		
43		
42		
41		
40		
39	25	
38	2 188	419
37	11 404	19 870
36	1 949	444
35		
34		
33		
32		
31		
30		
29		
28		
	79	80

(x coord.)

LISTING OF EASTERN CANADA NO_x EMISSIONS ON THE 127 km x 127 km GRID

NO_x (as NO_2)

CANADIAN EMISSIONS DATA - 1976 THROUGH 1980 - ANNUAL ESTIMATES (PRELIMINARY) (IN TONNES)

(y coord.)							
47							
46							
45							
44				41	14	7	182
43			618	413	271		
42		670	715	635	1 949	625	55
41		1 052	624	748	489	579	156
40		1 004	355	208	543	461	57
39	204	1 561	673	310	408	40	23
38	963	2 846	961	857	873	858	622
37	821	10 127	40 121	7 813	1 237	1 459	1 031
36		88	2 257	1 360	1 678	2 317	1 368
35					1 500	1 026	1 430
34							427
33							
32							
31							
30							
29							
28							
	51	52	53	54	55	56	57

(x coord.)

NO_x (as NO_2)

CANADIAN EMISSIONS DATA - 1976 THROUGH 1980 - ANNUAL ESTIMATES (PRELIMINARY) (IN TONNES)

(y coord.)							
47						1	
46							
45						24	
44							
43							1
42							
41			2				
40	9			5			
39	23	18					63
38	274	25			18	18	50
37	1 330	842	345			279	162
36	1 093	1 261	316		207	1 412	537
35	1 831	1 703	1 637	1 288	2 119	1 841	645
34	6 717		1 484	1 687	1 403	4 911	3 543
33				1 626	1 436	1 469	2 397
32				5 264	3 183	10 764	5 154
31					200	748	4 056
30					1 100	9 286	67 084
29					34 691	93 019	172 391
28				13 481	7 855	533	
	58	59	60	61	62	63	64

(x coord.)

NO_x (as NO_2)

CANADIAN EMISSIONS DATA - 1976 THROUGH 1980 - ANNUAL ESTIMATES (PRELIMINARY) (IN TONNES)

(y coord.)							
47							
46	15		3	1			
45				3		3	
44				1			
43			17		33		
42							
41						206	
40	37						17
39					19		733
38	12			125	163	354	
37	76	86	143	191	125	144	1 137
36	191	191	677	191	29	183	561
35	914	225	345	1 488	562	833	7 328
34	2 729	190	225	1 380	10 939	4 944	4 407
33	183	187	361	4 421	29 720	3 051	920
32	2 646	2 181	6 092	71 366	11 994	2 653	
31	2 623	34 266	13 616	105 327	6 761		
30	13 072	14 938					
29							
28							
	65	66	67	68	69	70	71

(x coord.)

NO$_x$ (as NO$_2$)

CANADIAN EMISSIONS DATA - 1976 THROUGH 1980 - ANNUAL ESTIMATES (PRELIMINARY) (IN TONNES)

(y coord.)	72	73	74	75	76	77	78
47							
46							
45							
44							
43	22						
42		213	311				
41		674	599	124	14		
40	483	899	1 877	899	121	374	
39		786	639	311	485	803	110
38		19	191	202	421	1 497	3 717
37	93	229	106		1 388	3 416	1 280
36	921	865			1 043	1 105	344
35	4 515	3 424		563	243		
34	2 668	6 720	6 822	1 366	19 805	59	
33	8 178	11 053	7 008	11 952	11 146		
32	2 652	19 919	11 303	24 161		0	
31	151	3 297	2 300				
30		67	71				
29							
28							
	72	73	74	75	76	77	78

(x coord.)

NO$_x$ (as NO$_2$)

CANADIAN EMISSIONS DATA - 1976 THROUGH 1980 - ANNUAL ESTIMATES (PRELIMINARY) (IN TONNES)

(y coord.)		
47		
46		
45		
44		
43		
42		
41		
40		
39	37	
38	2 461	294
37	3 942	11 200
36	1 400	448
35		
34		
33		
32		
31		
30		
29		
28		
	79	80

(x coord.)